San José Clean Energy
Community Choice Aggregation Business Plan

February 27, 2017

Prepared by:

EES Consulting, Inc.

A registered professional engineering and management consulting firm with offices in Kirkland, WA and Portland, OR

www.eesconsulting.com

570 Kirkland Way, Suite 100
Kirkland, WA 98033
Telephone: (425) 889-2700

In conjunction with

Bevilacqua-Knight, Inc. (BKi)

www.bki.com

800 West Sixth Street, Suite 1250
Los Angeles, CA 90017
Telephone: (213) 213-1960

Contents

Executive Summary

Introduction

California Assembly Bill 117 allows local governments to form community choice aggregations (CCA) that offer an alternative electric power option to constituents currently served electric power by investor owned utilities (IOUs). CCAs in California have "opt-out" programs, meaning that customers are automatically placed into CCA service, unless they proactively choose not to be. Under the CCA model, local governments gain control over their electric power supply and generation sources, while the incumbent IOU continues to provide transmission and distribution service. This gives CCAs the opportunity to use cleaner power supply options and reduce electric generation related greenhouse gas (GHG) emissions. In addition, CCAs determine their own electric power rates, decide how best to use revenues for CCA-related activities, and design their own programs.

This Business Plan ("Plan") evaluates the viability of a potential CCA for the City of San José, currently referred to as *San José Clean Energy* (SJCE). This Business Plan is distinguished from a technical study in that it includes a discussion of governance and operating structure alternatives, whereas a technical study focuses purely on the logistical and financial feasibility. The potential SJCE rates are compared to Pacific Gas & Electric (PG&E) rates. The City of San José provided historic energy use data for its service area. Using this information, EES Consulting estimated SJCE's power supply costs, administrative costs, electric loads, and future retail rates for SJCE and PG&E. These forecast rates are compared to determine if the proposed CCA can offer competitive rates, better products, and superior customer service. A sound financial and operational foundation for SJCE must be achievable before the other desirable attributes of a CCA can be enjoyed.

The Plan assumes seven overarching goals for the SJCE business:

- Increase the renewable energy in power mix to exceed the baseline power mix offered by PG&E by a minimum of 10 percent;
- Receive a share of CCA revenues for use on local, energy programs;
- Deliver local renewable energy development and energy-efficiency programs at or above current budget levels;
- Ensure low-income program offerings are, at minimum, on par with current PG&E offerings;
- Provide the City with option to assume operations of CCA;
- Keep customer rates cost competitive with PG&E's rates; and
- Reduce GHG emissions.

While SJCE has not yet officially adopted these goals, they serve as the foundation of this Plan. Once the SJCE goals are refined, adopted, and prioritized, modifications to this Plan may be appropriate.

Governance Structure

This Business Plan examines two governance structures. SJCE will have the option to operate as a single jurisdiction or as a member of an existing joint powers agency (JPA). The governance structure determines what entity would be responsible for providing policy direction to the CCA and ongoing reporting requirements. The two governance options include:

1. **Single Jurisdiction Model:** A single jurisdiction individually establishes and operates a CCA and therefore makes all policy decisions on revenues, power mix, and programs. All risk and liability associated with the CCA fall solely on this single jurisdiction. In this structure, it is recommended that the City develop contractual language to minimize risk to the general fund, maintain adequate operating reserves, proactively track regulatory activities, and manage its energy portfolio. Lancaster Choice Energy and CleanPowerSF are examples of single jurisdiction governance models.

2. **Joint Powers Authority (JPA) Model**: The JPA functions as an independent public agency, operating on behalf of its member jurisdictions with shared decision-making authority. This shared structure distributes the risks and liability across multiple jurisdictions, and minimizes risk to its member jurisdictions. Marin Clean Energy, Sonoma Clean Power, Peninsula Clean Energy, and Silicon Valley Clean Energy are examples of CCAs using the JPA model.

As part of this Business Plan, EES contacted five CCAs currently (or soon-to-be) operating in PG&E territory to explore the possibility of a merger. Of those contacted, Peninsula Clean Energy and Silicon Valley Clean Energy were the most amenable and promising JPA partners. If San José elects to join one of these organizations, it will be crucial to ensure that priorities of both partners are aligned. In short, the choice between the single jurisdiction and the JPA models comes down to weighing local control against the liability and effort involved with launching a new CCA.

Operational Structure

In contrast to the governing structures discussed above, the operating structure determines how the CCA will be staffed, managed, and operated. Operation of the CCA will involve a range of day-to-day functions including:

- Marketing and outreach
- Customer service
- Power supply contracts and scheduling
- Billing and data transfer with the IOU / California Independent System Operator (CAISO)
- Regulatory compliance with the California Public Utility Commission (CPUC), California Energy Commission (CEC), and CAISO
- Monitoring regulatory and legislative energy policy relevant to CCA competitiveness

These functions can be fulfilled by internal staff, external consultants, or a mix thereof; and, that mix can change as the CCA becomes fully operational. The choice of how to allocate these functions between internal and external resources through the pre-launch and launch phases is at the discretion of the governing body of the CCA. Existing California CCAs have opted for an organizational structure that, once the CCA is fully operational, is primarily comprised of internal staff with some continued support from consultants once fully operational.

For start-up, the Plan assumes that under a single jurisdiction model an operating team will be employed consisting of an Interim Executive Director, per the example of other CCAs in California, plus a few other CCA technical staff. This team would then be supported by outside consultants to assist with the management of the CCA until full operations are implemented.

For the longer term, SJCE has two options for staffing under the single-jurisdiction governance model after the initial start-up. The first option involves hiring internal staff incrementally to match workloads involved in forming SJCE, managing contracts, and initiating customer outreach/marketing during the pre-operations period (Full Staff Scenario). In option two, the CCA would hire just a few staff internally and contract out the remaining work to consultants (Minimum Staff Scenario). Throughout the rest of this Plan, it is assumed that SJCE will transition to the Full Staff Scenario. This scenario represents the highest cost scenario so as to maintain a conservative posture for the Plan's financial pro formas. Less costly options may be available to the CCA based on subsequent work to evaluate other staffing and operational options.

A variation on the Minimum Staff Scenario would be for SJCE's governing body to hire a third-party vendor (sometimes referred to as a "third-party turnkey" approach) or to join an existing CCA to operate the CCA with only three to four internal staff from the City acting as program managers. The third-party turnkey operational model is distinct in that the third party would provide financing for the CCA. Under the third-party turnkey approach, the governing body would issue a Request for Proposals (RFP) for the requested services to hire the vendor to operate the CCA. In this scenario, governance of the CCA would remain a responsibility of the City.

Load Forecast

SJCE is assumed to launch operations in three phases to allow the overall program and technical vendors to scale up services gradually, and mitigate start-up and operational issues. For the purposes of this Plan, it is assumed that SJCE would first provide service only to the City's municipally owned facilities[1] starting early in 2018, then expand to residential and small commercial customers in June of 2018, and finally offer service to all customers by November 2018. Exhibit ES-1 summarizes the loads, number of accounts, and revenues for each phase.

[1] This plan assumes Phase 1 includes both municipally-owned and operated facilities as well as those operated privately. However, the municipal wastewater facility was excluded as it is expected to generate its own power in the future.

Exhibit ES-1
SJCE Load, Customers, and Revenue by Phase

Phase	Assumed Start	Eligibility	Average Customer Accounts	Total Load (GWh)	Peak Demand (MW)	SJCE Normalized Annual Operating Revenues
Phase 1	January 2018	Municipal Facilities	1,600	74	17	$9 million
Phase 2	June 2018	Municipal, Residential, and Small Commercial	293,000	2,013	533	$160 million
Phase 3	November 2018	All Customers	300,000	4,015	957	$350 million

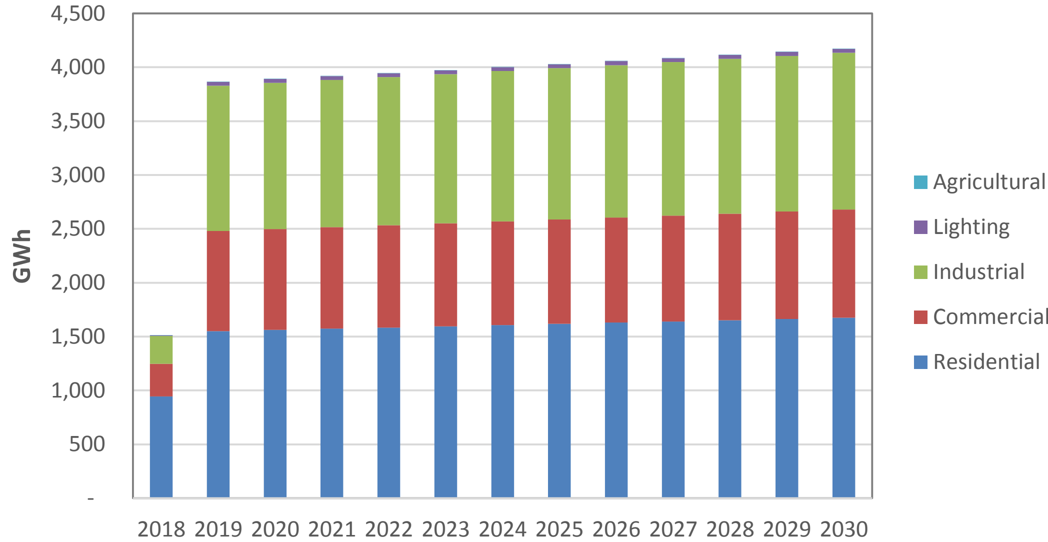
Data for phases 2 and 3 include accounts, load, peak, and revenues from previous phases. Estimates assume an 85% and 75% participation rate for residential and non-residential customers respectively. Loads are expressed as wholesale load, including 7 percent transmission and distribution losses. Revenues and loads are presented on an annual basis assuming each phase would be run for a full year. Operating Revenues include CCA costs, Franchise Fee Surcharge, and PG&E's Power Charge Indifference Adjustment (PCIA) charges (See Glossary).

It should be noted that the timing for launching Phase 1 is difficult to estimate precisely. This Plan assumes the launch schedule provided in Exhibit ES-1. However, a reasonable project schedule is shown in Appendix A. Even if the actual launch date were to slip by several months, the Plan's results and recommendations would not change materially. However, a significant change in the phasing schedule would merit a revised financial analysis.

Loads are expected to grow only marginally over the study time horizon (0.7% annually), as decreasing per-customer energy use is roughly offset by growth in number of customers[2]. Exhibit ES-2 illustrates projected growth over the study period.

[2] California Energy Commission, "California Energy Demand 2015-2025 Final Forecast, LSE and Balancing Authority Forecasts." Growth projections for Silicon Valley Power were chosen as the most representative growth rate for San José. Accessed 10.19.2016 at: http://www.energy.ca.gov/2014_energypolicy/documents/demand_forecast_cmf/LSE_and_BA/

Exhibit ES-2
Projected Load by Sector



Power Supply

The City of San José will likely seek to maximize the use of local, cost-effective renewable generation resources, while offering rates that are competitive with PG&E. Power purchases from renewable and non-renewable resources will supply the majority of remaining power supply needs.

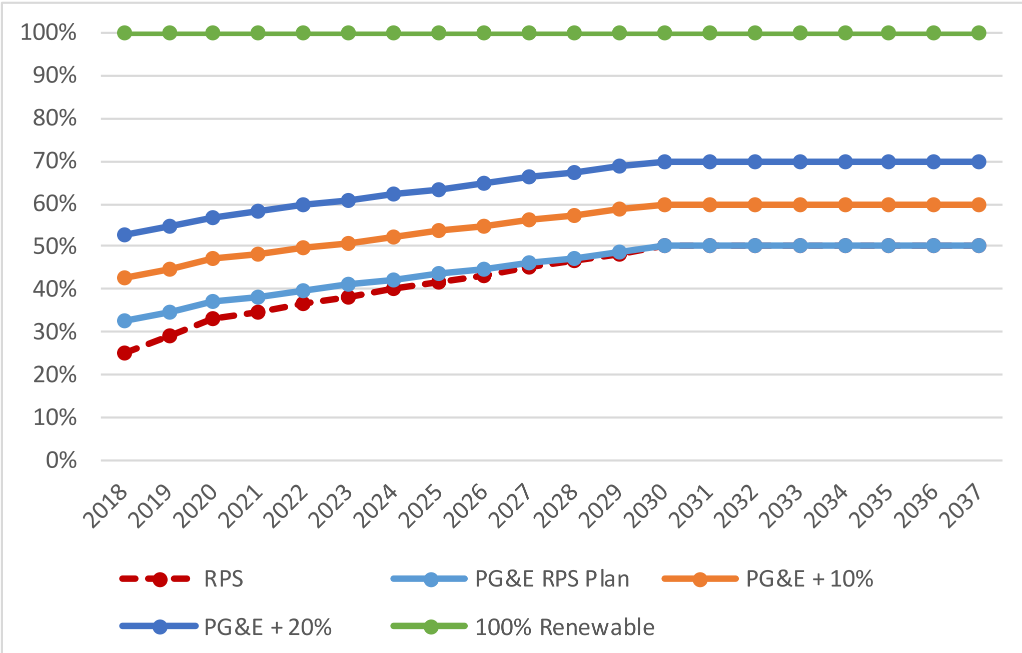
This Plan presents four *representative* resource portfolios to develop pricing estimates for SJCE customers and evaluate the impact of varying levels of renewable resources in SJCE's portfolios. For each scenario, we discuss the share of energy sourced from renewable sources and power sourced from greenhouse gas-free (GHG) sources. Renewable resources refer to resources that qualify under the state's Renewable Portfolio Standard (RPS), such as solar and wind power. GHG-free power refers to energy sourced from any non-GHG emitting resource, including both the RPS-compliant sources mentioned above as well as nuclear power and large hydroelectric power. At present, PG&E's power supply is 30 percent renewable and 59 percent GHG-free. The cost of each of these portfolios was also calculated assuming 10% of renewables coming from local sources. These portfolios are as follows:

- **Match PG&E**: SJCE will match PG&E on both renewable and GHG-free energy sources.
- **PG&E + 10%**: SJCE will exceed PG&E's renewable and GHG-free generation by 10%
- **PG&E + 20%**: SJCE will exceed PG&E's renewable and GHG-free generation by 20%

- **100% Renewables**: SJCE will supply 100% of retail load with renewable power[3].

Exhibits ES-3 and ES-4 illustrate these four portfolios in terms in terms of renewable and GHG emissions relative to RPS requirements and PG&E's projected GHG emissions.

Exhibit ES-3
Renewable Energy Purchase Scenarios Compared to RPS Requirements[4]

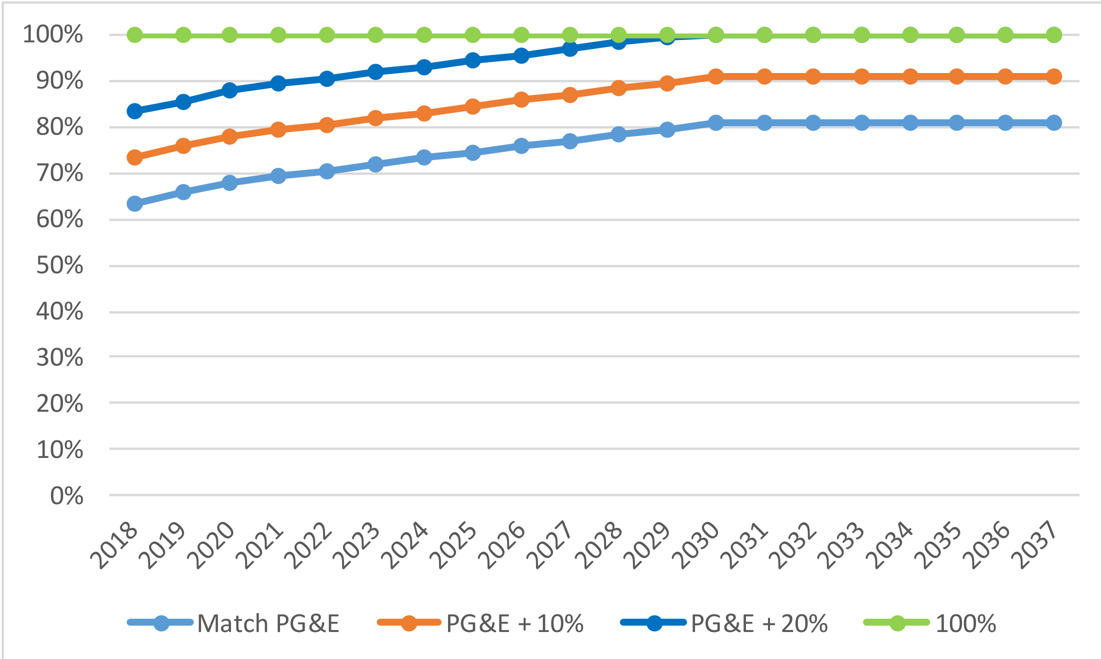


Note: The "RPS" line shown above includes inter-year targets; inter-year targets are advisory only and not required for compliance. Compliance requirements are 25 percent in 2018-19, 33 percent in 2020-23, 40 percent in 2024-26, 45 percent in 2027-29 and 50 percent beginning in 2030.

[3] This scenario is modeled to develop potential pricing for customers seeking to purchase 100% renewable power from SJCE.

[4] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M158/K845/158845742.PDF

Exhibit ES-4
Percent of Load Served by Greenhouse Gas-Free Resources[5]



Per resource portfolio standards (RPS) standards/requirements[6], smaller scale renewable installations (e.g. rooftop solar) installed by SJCE customers are not counted in the renewable percentages shown in this Plan. Only power purchased and paid for by SJCE from RPS-eligible installations will count towards the renewable percentage.

Rates

EES developed indicative estimates of retail rates for SJCE under each of the four power supply scenarios and compared these rates to PG&E's comparable offering. The SJCE rate estimates include power supply costs, CCA start-up costs, staffing and operating costs, consulting support, PG&E billing and regulatory charges, financing costs, building of financial reserves, and PG&E pass-through charges, such as the Power Charge Indifference Adjustment (PCIA) charge and Franchise Fee Surcharge. The detailed financial pro forma in support of these rates can be referenced in Appendix B of this Plan. The resulting rate comparisons are summarized in Exhibit ES-5.

[5] http://www.pgecurrents.com/2016/04/25/infographic-power-mix-2015/

[6] http://www.energy.ca.gov/portfolio/documents/rps_certification.html

Exhibit ES-5 Indicative Rate Comparison in $/kWh					
Rate Class	**2017 PG&E Bundled Rate***	**Indicative SJCE RPS Bundled Rate**	**Indicative SJCE 10% more Green Bundled Rate**	**Indicative SJCE 20% more Green Bundled Rate**	**Indicative SJCE 100% Green Bundled Rate**
Residential	0.19971	0.1913	0.1921	0.1953	0.2063
Small Commercial	0.22515	0.2157	0.2166	0.2202	0.2326
Medium Commercial	0.20053	0.1921	0.1929	0.1961	0.2071
Large Commercial	0.17618	0.1688	0.1695	0.1723	0.1820
Street Lights	0.21785	0.2087	0.2096	0.2131	0.2250
Standby	0.14608	0.1399	0.1405	0.1429	0.1509
Agriculture	0.17606	0.1687	0.1694	0.1722	0.1819
Industrial	0.13985	0.1340	0.1345	0.1368	0.1445
Total	**0.18779**	**0.1799**	**0.1807**	**0.1837**	**0.1940**
Initial Rate Savings in 2019 from PG&E Bundled Rate		**4.2%**	**3.8%**	**2.2%**	**-3.4%**
Rate Savings After Fully Operational		**4.8 – 9.4%**	**4.5 – 8.9%**	**2.7 – 7.2%**	**-2.7 – 1.3%**

*PG&E bundled average rate based on PG&E's 2017 Rates

Exhibit ES-6 provides the comparison for a residential customer of SJCE projected rates to PG&E's bundled rate and PG&E's rate offerings for additional renewable power. For 2017, PG&E charges $0.0261 per kwh for each additional renewable kwh requested by a residential customer.

Exhibit ES-6 Residential Rate Comparison in $/kwh for 2019			
	PG&E Indicative Rate	**SJCE Indicative Rate**	**Percent Difference**
PG&E Match Scenario (35% Renewable)	0.19971	0.1913	4.2%
PG&E + 20% (50% Renewable)	0.2128	0.1953	8.2%
100% Renewable	0.2232	0.2063	7.6%

Exhibit ES-6 shows that SJCE's portfolios with additional renewable resources can provide savings of approximately 4-8 percent to CCA residential customers over PG&E's comparable renewable rate plans.

EES used the financial analysis in Appendix B to determine rate savings noted above. The financial analysis assumes total CCA revenues are reduced for operating expenses and debt service on start-up loans ($4M), cash working capital requirements ($50M), and contribution to financial reserves. The Plan assumes SJCE will accumulate reserves equivalent to 90 days of operating costs over the first four years of operation. This strategy allows for accumulation of sufficient reserves for working capital, rate stabilization and cost uncertainties in the initial years. Additionally, this Plan assumes funding for a "new capital –intensive project" starting in 2022. The project and reserve funds could be used to pay off outstanding loans or support electric vehicle and charging station programs, low income programs, local renewable resource development, and CCA-related economic development programs as ultimately decided by SJCE's governing body. The reserve and new project fund balances are shown in Exhibit ES-7.

Exhibit ES-7
Accumulative Fund Balances for Financial Reserves and New Programs Under the RPS +10% Scenario

Year	Accumulative Financial Reserve Funds ($ x 1000)	Accumulative New Project/Rate Reduction Funds ($ x 1000)	Total Financial Reserves ($ x 1,000)
2018	$11,511	$0	$11,511
2019	$31,808	$0	$31,808
2020	$51,650	$0	$51,650
2021	$76,081	$0	$76,081
2022	$90,671	$14,589	$105,260
2023	$90,671	$48,816	$139,487
2024	$90,671	$86,331	$177,002
2025	$90,671	$127,556	$218,226
2026	$90,671	$172,257	$262,928
2027	$90,671	$220,908	$311,579
2028	$90,671	$273,941	$364,612
2029	$90,671	$331,210	$421,881
2030	$90,671	$392,724	$483,395

These new project and financial reserve fund balances can be used for CCA-related activities as directed by SJCE's governing body and allowed by state law. These fund balances could also be used for rate deductions in addition to those noted above.

Greenhouse Gas Reductions

Based on the power supply strategy described previously, GHG emission reductions due to additional renewable resource procurement resulting from the formation of SJCE are estimated to range from 152,000 to 264,000 metric tons carbon dioxide equivalent (MT CO_2e) per year in 2019 assuming SJCE's share of power from renewable energy is 10 percent greater than PG&E. This equates to removing up to 56,000 passenger vehicles from the road or the energy usage from nearly 28,000 homes each year.[7] This represents a 10 percent to 18 percent reduction in San José's GHG emissions from electricity generation[8]. In the scenario wherein SJCE achieves 20

[7] https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

[8] https://www.sanjoseca.gov/DocumentCenter/View/55505

percent higher RPS than PG&E, the estimated range of GHG emission savings is 304,000 to 528,000 MT CO_2e per year in 2019, representing a reduction of 21 percent to 36 percent of San José GHG emissions from electricity generation. This reduction equates to removing up to 112,000 passenger vehicles from the road each year or the energy usage from nearly 56,000 homes. The baseline for comparison is the projected resource mix used by PG&E in the same time period. Exhibit ES-8 details these reductions.

Exhibit ES-8
Comparison of GHG Reduction by SJCE

	10% Additional Renewable	20% Additional Renewable
2019 Load (GWH)	3,769	3,769
SJCE Additional Renewable (GWH)	377	754
CO2 reduction – Low (Metric Tons of CO_2e)	152,267	304,535
CO2 reduction – High (Metric tons of CO_2e)	263,830	527,660

These changes would move San José substantially closer to achieving its third Green Vision Goal[9]: receiving 100 percent of electrical power from clean, renewable sources by 2022. PG&E's current power portfolio is 30 percent renewable[10], so exceeding PG&E's by 10 percent or 20 percent would move the City to 40 percent or 50 percent of that target.

Economic Development and Programs

A major motive for the development of a CCA is to bolster local economic development. There are several programs that CCAs can offer to stimulate additional local economic development in their service area. One is a special economic development rate to encourage manufacturers to site in San José thus supporting San José's strategy to stimulate manufacturing jobs.

Another program type to promote economic development is to provide incentives for businesses to locate in the service area, remain there, or expand. In order for economic incentives to be provided, the utility must show that the addition of the new customers will benefit (or not harm) the existing rate payers. PG&E offers a wide range of rebates to businesses across different sectors, including agricultural, computing and data services, food services and refrigeration, HVAC, and lighting[11]. While these rebates would still be available to SJCE's customers, SJCE could offer similar rebate programs better targeted to the business sectors of interest to their service area. If, for example, a large industrial customer would like to locate within PG&E/SJCE service

[9] http://www.sanjoseca.gov/index.aspx?NID=2737

[10]https://www.pge.com/pge_global/common/pdfs/your-account/your-bill/understand-your-bill/bill-inserts/2016/11.16_PowerContent.pdf

[11]https://www.pge.com/en_US/business/save-energy-money/business-solutions-and-rebates/product-rebates/product-rebates.page

area, increased efficiency may result in decreased costs to all other customers, thus an incentive could be paid to the new industrial customer.

Below are estimates of the direct, indirect, and induced economic development impacts that would result from the formation of SJCE, the associated investment in the local economy, and the rate savings accrued throughout the service area. The Input-Output (IO) model used in the Plan to determine the economic impact of rate reduction in the City, IMPLAN, displays the economic impacts of changes in rates into four categories: employment, labor income, value added, and output. Employment is the number of jobs gained or lost.

Exhibit ES-9 shows the economic impact resulting from $23 million in electric bill savings (the estimated annual rate savings after SJCE is in full operation offering a 10 percent more renewable power supply). It is estimated that these savings will create approximately 101 additional jobs in the San José area and over $11.5 million in labor income. It is also projected that the total value added will be approximately $18.5 million and output will be over $31.6 million.

Exhibit ES-9
$23 Million Rate Savings Effects on San José Economy

Impact Type	Jobs (FTE)	Labor Income	Total Value Added[12]	Output[13]
Direct Effect	42.3	$6,748,462	$10,728,806	$19,359,765
Indirect Effect	26.1	$2,829,014	$4,335,315	$6,982,253
Induced Effect	32.6	$2,005,331	$3,505,898	$5,280,160
Total Effect	101.0	$11,582,808	$18,570,019	$31,622,178

In addition to increased economic activity due to electric bill savings, potential local renewable projects can also create job and economic growth within the San José area. As an example of the macroeconomic activity caused by local commercial renewable resources, this Plan assumes the installation of 50 crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 50 MW. Overall, the building of a 50 MW solar project is projected to create $87 million in earnings and $188 million in output (GDP) in the local economy along with 1,636 jobs during construction and 14 full-time jobs ongoing. SJCE can consider installing a number of larger local solar projects such as the one described once reserves are available to fund such projects.

This Plan also discusses six program categories that SJCE could develop to support customers, stimulate its economy, or encourage investment in renewable energy. These energy- or GHG-

[12] In the context of IMPLAN, value added is very similar to gross domestic product (GDP). It includes four components: wages, business income, other income, and indirect business taxes. Therefore, it accounts for the value of work, land, and capital. It excludes the costs of generating the additional value.

[13] Output is an approximate measure of the money that the estimated rate decrease drops into the local economy to be spent on local goods, services, and wages. Output equals the sum of the value of intermediate goods and services, wages, business income, other income, and indirect business taxes.

related programs include Net Energy Metering (NEM), feed-in tariffs, electric vehicle and charging station programs, low income programs, local generation resource development, and general energy- or GHG-related economic development programs. As noted earlier, the Plan establishes a reserve fund to support these and other programs. The final selection of which programs to support with these reserve funds is the ultimate decision of SJCE's governing body and is an area of decision-making outside of the scope of this Plan.

Risks and Uncertainties

The results of this Plan are subject to uncertainties. These uncertainties are evaluated in the Plan's Sensitivity and Risk Analysis section. The list below provides a summary discussion of the key uncertainties of this Plan. In depth discussion and quantification of risks are provided in the body of the Plan. A detailed comparative table of risks to CCA viability is also provided in the Sensitivity and Risk Analysis section of the Plan, in Exhibit 35.

- *Market Price Forecasts* – Market prices (and forecasts) are continually changing. The market price forecasts for electricity and natural gas utilized in this Plan are based on the best currently available information regarding future natural gas and electricity prices, and have been confirmed by recent wholesale power transactions in northern California. However, these types of forecasts vary over time. Thus, a range of market price forecasts are evaluated in the sensitivity analysis.
- *Retail Rate Forecasts* – The Plan forecasts retail rates for both SJCE and PG&E over the study period. These forecasts are based on current information regarding inflation, RPS requirement and other cost drivers. Unexpected rate impacts are discussed in the sensitivity analysis.
- *Forecast Load and Customer Growth* – The Plan bases the load forecasts on customer growth. Each of these forecasts includes some uncertainty. To illustrate the impacts of load uncertainty, low, medium, and high load forecasts are analyzed in the sensitivity analysis.
- *Regulatory Risks* – Unforeseen changes in legislation (California Public Utility Commission, state legislation and federal legislation) may impact the results of this Plan. Sensitivities on these risks are also provided. Notably, PG&E's recent proposal to replace the Diablo Canyon Nuclear Power Plant was paired with a plan to introduce a new non-bypassable charge. At the time this Plan was written, there remains uncertainty about how the CPUC will rule on this proposal.

This sensitivity analysis shows that the SJCE rates could be greater than PG&E rates if:

- The Power Charge Indifference Adjustment (PCIA) increases by more than 25% without an offsetting power supply cost reduction. The PCIA is a charge assessed by the IOU to cover generation costs for facilities or contracts acquired prior to CCA formation (i.e., stranded costs)
- SJCE loads are much less than forecast. For example, if SJCE only achieves Phase 1 participation, it would be difficult to operate SJCE at lower rates than PG&E.

- Wholesale market prices drop to 25% lower than present levels. As power costs to both PG&E and SJCE are decreased, the PCIA would increase. This causes additional risks to SJCE even though power procurement costs could be lower.

Each of these three scenarios has a low probability of actually occurring and can be managed if they do (see Exhibit 35). SJCE can mitigate risk from PCIA increases or from wholesale market price drops by investing in a power portfolio that is balanced between long and short-term contracts and by maintaining a healthy reserve fund to cushion rates through periods of high PCIA rates (as Marin Clean Energy and Sonoma Clean Power have done repeatedly). In the event that SJCE's load is significantly lower than expected as a result of poor participation, SJCE could expand its service territory, merge with another existing CCA, or reduce overhead expenses such as staff.

The PCIA level should be much more stable going forward as regulatory remedies are in play to stabilize the CCA and because the CCA community has become very vigilant in this area. Stranded costs from existing contracts (which is the basis for the PCIA) are expected to decline as contracts expire and market prices increase. In addition, PG&E is now taking into account the potential loss of load to CCAs and are not likely to continue to purchase power on behalf of CCA customers, thus not incurring additional stranded costs on behalf of CCA customers.

Finally, this Plan assumes a relatively low customer participation rate of 85 percent for residential customers and 75 percent for non-residential customers, compared to the roughly 95 percent to 85 percent participation rates seen in California's currently operating CCAs. It is very unlikely SJCE loads will not meet or exceed those assumed in the Plan.

Conclusions

This Plan concludes that the formation of SJCE is financially prudent and could yield considerable benefits for residents and businesses in the SJCE service area. First, if SJCE elects the PG&E RPS + 10% power supply model, SJCE customers will likely enjoy rate savings estimated to grow from 3.8 percent in 2018 to 8.9 percent by 2030 relative to PG&E's rates. Second, the PG&E RPS + 10% power supply model would reduce GHG emissions by 152,000 to 264,000 metric tons carbon dioxide equivalent (MT CO_2e) per year in 2019, lowering San José's GHG emissions due to electricity use by 10 to 18 percent[14]. Finally, the formation of SJCE could lead to roughly 100 additional jobs and generate over $31 million in additional GDP due to rate savings. SJCE would also give City residents and businesses local control over their power supply and energy efficiency programs. Even with these stated rate savings, significant financial reserve funding is still generated to support new local programs, build CCA reserves, and/or offer additional rate savings to CCA's customers. While there are risks associated with a CCA, prudent planning and thoughtful growth of programs would result in funds to manage risks. On balance, the formation of a CCA

[14] San José Greenhouse Gas Inventory, AECOM, April 2016: https://www.sanjoseca.gov/DocumentCenter/View/55505

for the City of San José is financially feasible and results in beneficial environmental and economic impacts.

If San José opts to proceed with forming and launching a CCA, the City should review, refine, and/or add to its seven overarching goals to ensure they are clear and consistent with City priorities particularly related to local economic development, risk management, renewable portfolio targets, and GHG-free power targets (see Summary and Recommendations).

Introduction

Background

California's legislature passed AB 117 in 2002 (amended in 2011 by SB 790) authorizing all cities, counties, or groups of cities and counties to provide electric service to customers currently served by Investor-Owned Utilities (IOUs). CCA's are the organizations providing this service. California CCAs are customer opt-out programs that provide power supply, data management, and energy program management, while the incumbent IOUs continue to provide transmission and distribution (wires) service. This legislation states that CCAs will enable California to experience more competitive electricity rates, a more renewable power supply mix, and growth in local resources and associated economic activity. Currently, there are five CCAs operating in California and these utilities offer competitive rates for power supply that have a higher percentage of renewable resources. CCAs have also proven to promote local economic activity and their associated benefits. Several other California cities and counties are currently evaluating the feasibility of CCA formation within their jurisdictions. This background information can be found in Appendix D. Technical terminology and acronyms used in this Business Plan are defined in Appendix E – Glossary.

The Plan assumes seven primary goals for the SJCE business:

- Increase the renewable energy in power mix to exceed the baseline power mix offered by PG&E by a minimum of 10 percent;
- Receive a share of CCA revenues for use on local, energy programs;
- Deliver local renewable energy development and energy-efficiency programs at or above current budget levels;
- Ensure low-income program offerings are, at minimum, on par with current PG&E offerings;
- Provide the City with option to assume operations of CCA;
- Keep customer rates cost competitive with PG&E's rates; and
- Reduce GHG emissions.

While SJCE has not yet officially prioritized its overarching goals, these seven goals are the foundation of this Plan and equal weight is given to all seven goals throughout the development of this Plan. Once the SJCE overarching goals are prioritized, modifications to this Plan may be appropriate.

Objective

This Plan evaluates the prudency of forming a CCA in the City of San José, henceforth referred to in this Plan as SJCE. This Business Plan is distinguished from a technical study in that it includes a discussion of governance and operating structure alternatives, whereas a technical study focuses purely on the logistical and financial feasibility. The proposed CCA will provide power supply and customer programs[15], while Pacific Gas and Electric (PG&E) will continue to provide transmission and distribution services. Customers will be part of the SJCE program unless they proactively opt-out.

This Plan estimates SJCE's power supply costs, administrative costs, electric loads, and future retail rates for SJCE and PG&E. These forecast rates are compared to determine if the proposed CCA can offer competitive rates while meeting SJCE's goals. A sound financial and operational foundation for SJCE must be achieved before the other desirable attributes of a CCA can be enjoyed.

Governance Structure

SJCE will have the option to operate as a single jurisdiction or as a member of a JPA. Single jurisdiction CCAs maintain full control over their operations, rate setting, and revenues, but must also bear the full financial risks of the CCA. In contrast, operating as a JPA allows CCAs to spread the expenses and risks across multiple parties at the cost of reduced control. A JPA could be formed with an existing operational CCA or other local governments interested in forming one. There are currently multiple CCAs with each governance model operating in California.

EES contacted five currently (or soon-to-be) operating CCAs within PG&E's service area to discuss the possibility for the City of San José to join into their service area rather than form its own program. Exhibit 1 lists the response from each CCA:

Exhibit 1
Possible JPA Partners

CCA	Response
Marin Clean Energy (MCE)	Not interested
Sonoma Clean Power (SCP)	Not interested
CleanPowerSF	Not currently interested*
Peninsula Clean Energy (PCE)	Interested, amenable to further discussion
Silicon Valley Clean Energy (SVCE)**	Interested, amenable to further discussion

*CleanPowerSF is not currently open to merging with San José, but indicated that they could reassess after their next implementation phase.
**SVCE plans to launch in April 2017.

[15] Customer programs may include energy efficiency, net energy metering, programs for low income residents, electric vehicle rates, as well as a range of other possible offerings.

Benefits of Joining an Existing CCA

By joining an existing program, San José would avoid the risk and expense of arranging financing for the capital intensive process of purchasing power and for organizational startup costs including staffing and consultants. Under the JPA model, San José would elect a representative to the Board of the JPA. Beyond that representative, no additional staff or consulting services would be needed outside of those provided by the JPA. If SJCE is a stand-alone entity, care must be taken so that the City's general fund is not liable for the debts of the SJCE.

Ongoing operational costs *could* also be lower for customers of a larger CCA than for customers of a San José-only CCA by sharing the costs of staffing, financing, and legal services. In terms of power supply, however, costs are unlikely to differ between a stand-alone SJCE and a larger CCA because the load shape of San José is quite similar to that of both possible CCA partners. In addition, bypassing these start-up steps would reduce the workload and the time until San José's customers can be served by a CCA.

Finally, joining an existing CCA could streamline SJCE's power procurement process. San José's current municipal purchasing policy could be too slow to allow a CCA operating under those rules to buy market electric power contracts at competitive rates. Joining an existing CCA would grant purchase power to the JPA and thereby avoid the City's purchasing policies.

The alternative would be for SJCE's governing body to authorize SJCE to handle supply contracts differently than all other city contracts such that SJCE could match the commercial pace of the power market. This is the current arrangement between CleanPowerSF and the City of San Francisco. San José could either replicate CleanPowerSF's model if it operates independently or it could join an existing CCA.

Downsides of Joining an Existing CCA

Depending on the governing system of its CCA partners, San José may lose some control over decisions effecting the operation of the CCA, its rates, and its programs. For example, decisions that impact rates will be shared in some capacity with other communities that are members of the CCA. If these communities disagree on what power supply options are desirable, this may result in compromise.

In addition, the benefit of local programs and local economic development may be diluted through partnership with other communities, resulting in programs that are less targeted to the needs of San José. However, both of these "cons" could be overcome through negotiation and/or governance arrangements with CCA partners.

Governance

Both of the potential CCA partners use a similar system of CCA governance. Each member community (town, city, or county) elects a director to the governing body, except in the case of San Mateo County in Peninsula Clean Energy, which elects two directors. Votes are cast on a one-vote-per-director basis, unless two or more directors requests to implement a “voting shares” vote. A voting shares vote weights each director’s vote on the basis of the load share of that director’s customer base.

San José would likely have the opportunity to discuss possible exceptions or amendments for their integration into an existing CCA. However, understanding this voting system and being comfortable with its outcomes will be essential if San José is to join an existing CCA. Exhibit 2 compares the attributes of operating as a single jurisdiction vs merging with the three possible JPA partners.

Exhibit 2
Governance Option Tradeoffs

	Single Jurisdiction	**Peninsula Clean Energy**	**Silicon Valley Clean Energy**	**CleanPowerSF***
Liability to San José General Fund	Possible liability	Reduced liability	Reduced Liability	Reduced liability
Control	Total control	1 of 23 voting members**	1 of 13 voting members**	Unknown/ Negotiable
Goals	City Decision	75% GHG free (100% GHG free by 2021) Competitive Rates (5% lower) Stimulate local DER Projects	100% GHG free Competitive Rates 1% of revenue to local renewable projects and energy programs	Cleaner energy that protects the environment and supports the local economy
Base Power Product	City Decision	50% renewable, 75% GHG-free	50% renewable, 100% GHG-free	35% renewable
Local Programs	City decision	Negotiable, but possibly reduced focus on San José	Negotiable, but possibly reduced focus on San José	Negotiable, but possibly reduced focus on San José
Power Scheduling	Need authority from governing body to make procurement decisions independently/ quickly in order to participate in the power market	Already operating as a successful power market participant	Already operating as a successful power market participant	Already operating as a successful power market participant
Effort	High	Medium	Medium	Medium

*CleanPowerSF is not currently open to merging with San José, but indicated that they could reassess after their next implementation phase.

**Both PCE and SVCE have provisions in their JPA allowing an alternate "load-weighted" voting system to be triggered if two or more members request to have it. In the event of a load-weighted vote, San José's large load size would give it a roughly 50% voting share in both CCAs, as all three entities (PCE, SVCE, and San José) have roughly the same size energy load.

Next Steps

The central question to ask in considering whether or not to join an existing CCA is if that CCA partner's goals align with those of the City of San José. For example, Silicon Valley Clean Energy is currently planning to offer 100 percent GHG-free power as their standard power option at rates that are currently 1 percent lower than PG&E's. In contrast, Peninsula Clean Energy plans to offer rates that are 5 percent lower than PG&E's while offering 75 percent GHG-free power as their standard option. These different baseline offerings reflect differences in organizational priorities between the two.

Business Plan Assumptions

For this Plan, it is assumed that SJCE will be established under the single jurisdiction model as a department within the City of San José organization. As a single jurisdiction entity, SJCE will have to perform all organizational and operational start-up activities. If SJCE joins an existing JPA, the start-up activities would be simpler. SJCE will be formed to promote, develop, and manage electricity-related projects and programs for SJCE's residences and businesses. SJCE activities would be overseen by the appointed governing body, likely the City Council, which will have primary decision-making responsibility. The ultimately chosen governing body will adopt an Implementation Plan, as required by the CCA legislation (AB 117), and register SJCE with the California Public Utilities Commission (CPUC) as a CCA.

Operational Structure

If SJCE operates as a single jurisdiction, for example as a department within the City, its governing board could choose to fulfill staffing needs along any point from the fully in-house to fully outsourced continuum. One option would aim to minimize the use of outside consultants and hire sufficient staff in-house to manage all necessary tasks (Full Staff Scenario).

At the other extreme, SJCE could elect a maximally outsourced staffing model, often referred to as "third-party turnkey." In this scenario, the CCA would hire the minimal City staff needed to oversee external contracts. Consultants would then take on all remaining tasks, including financing of the CCA. This has the advantage of mitigating the City's financial risk, with the downside of higher private borrowing rates translating into higher power rates for customers.

Finally, SJCE could elect any point in between these two extremes. One selection could mimic the third-party scenario except that San José acquires its own financing (Minimum Staff Scenario).

Most operating CCAs have started with minimal staffing, supported by consultants, in the launch and early operations stages and then transitioned over time to additional staff in-house while retaining some consultant support. The third-party turnkey option has not yet been employed by a CCA. Humboldt County, operating as Redwood Coast Energy Authority (RCEA), did seek a third-party turnkey provider in an RFP released in December of 2015[16]. While RCEA ultimately awarded its RFP in three separate contracts (power, marketing, data management) and will have the launch in May 2017 financed by the primary third party provider (The Energy Authority), it has an existing JPA which currently employs 20 staff[17] and plans to train and phase-in additional JPA staffing over the first two to five years of operation[18]. RCEA allocated $2.5 million for staffing costs for its start-up phase[19].

The Plan assumes that SJCE will be operated as a department within the City of San José and be staffed with SJCE administrative staff and outside technical consultants. Under this assumed structure, SJCE operations will be the responsibility of an Executive Director. The Executive Director will manage staff, consultants, and third-party providers, in accordance with the general policies established by SJCE's governing body.

Initially, it is assumed that SJCE will operate with limited staff supported by consultants experienced in power procurement, data management, and utility operations. If SJCE decides to transition some of its administrative and operational responsibilities to internally staffed positions, SJCE could reach a full time staff of approximately 19 employees to perform its responsibilities, primarily related to program and contract management, legal and regulatory, finance and accounting, energy efficiency, marketing, and customer service. Technical functions associated with managing and scheduling power suppliers and those related to retail customer billings will likely still be performed by an experienced third-party consultant. The proposed organization chart for SJCE under full scale operations is provided below in Exhibit 3.

---

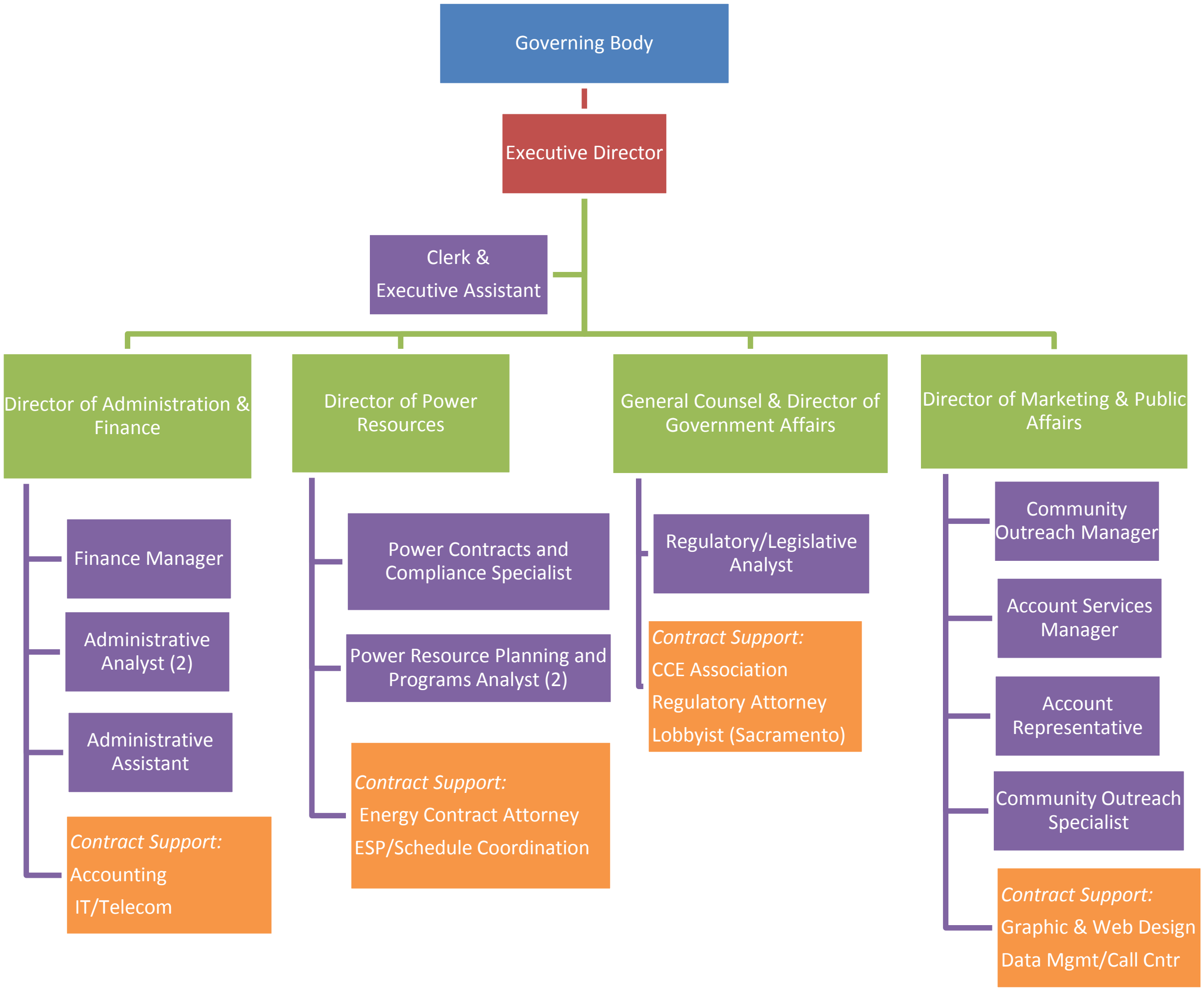
[16] http://www.redwoodenergy.org/images/Files/CCA/RCEA-CCA-RFP-15-001-REVISED-1-6-16.pdf

[17] http://www.redwoodenergy.org/images/Files/CCA/RCEA-Implementation-Plan-Final_web.pdf

[18] http://www.redwoodenergy.org/images/Files/CCA/RCEA-CCA-Roadmap-11-6-15.pdf

[19] http://www.redwoodenergy.org/images/Files/CCA/RCEA-Implementation-Plan-Final_web.pdf

Exhibit 3
Sample Organization Chart



Plan Methodology

This Plan evaluates the costs and resulting rates of operating SJCE and compares these rates to a PG&E rate forecast for the years 2018 through 2030. This pro forma feasibility analysis models the following cost components (please refer to the section "SJCE Cost of Service" for the detail):

- Power Supply Costs:
  - Wholesale purchase
  - Renewable purchases
  - Procurement of resource adequacy capacity (System, Local and Flexible capacity products)

  - Other power supply and charges
- Non-Power Supply Costs:
  - Start-up costs
  - SJCE staffing and administration costs
  - Consulting support
  - PG&E and regulatory charges
  - Financing costs
- Pass-Through Charges from PG&E:
  - Transmission and distribution charges
  - Power Charge Indifference Adjustment (PCIA) Charge, CRS charges (PPP and NDC)
  - Franchise Fee Surcharge

The information above is used to determine the retail rates for SJCE. SJCE rates are then compared to the PG&E projected rates for SJCE service area.

Plan Organization

This Plan is organized into the following main sections:

- Load Requirements
- Power Supply Strategy and Costs
- SJCE Cost of Service
- Products, Services, Rates Comparison and Environmental/Economic Considerations
- Sensitivity Analysis
- Summary and Recommendations

Each section is discussed in more detail below.

Load Requirements

The viability of SJCE depends in part on the number of customers that participate in the CCA as well as the quantity of energy they consume. This section of the Plan provides an overview of these projected values and the methodology used to estimate them.

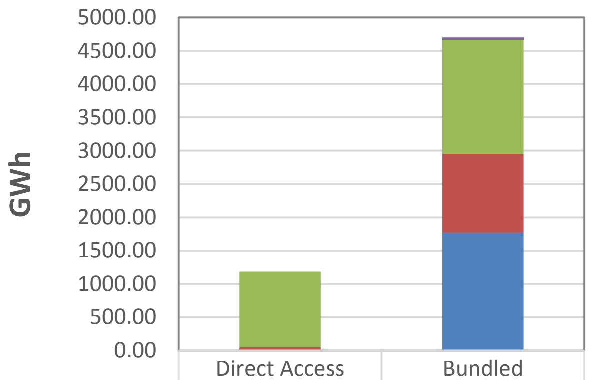
Historical Consumption

PG&E provided monthly historical data on energy use (kWh) and non-coincident peak load (kW) for each customer in San José for the 2015 calendar year. EES aggregated this data by rate class in each month for both bundled (full service) and direct access customers. In total, bundled residents and businesses within the City of San José purchased 4,763 GWh of electricity in 2015 from PG&E.

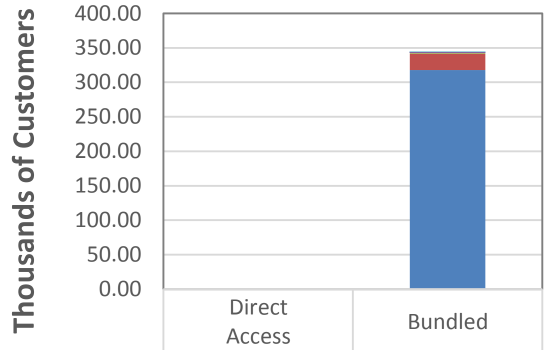
Bundled and Direct Access Customers

Bundled customers purchase the electric power, transmission and distribution from the IOU. Direct access (DA) customers buy only the transmission and distribution service from the IOU and purchase power from a competitive Electric Service Provider (ESP). At present, bundled customers make up over 99 percent of total customer accounts in San José and 80 percent of the total energy use. DA customers account for under 1 percent of customers with just 617 accounts. However, because they are primarily large industrial users, they use nearly 20 percent of the annual energy. Exhibit 4 summarizes energy consumption and number of accounts for bundled and DA customers in 2015.

Exhibit 4
Bundled and Direct Access Load and Accounts in 2015



	Direct Access	Bundled
Agricultural	0.00	1.59
Lighting	0.00	30.63
Industrial	1129.57	1711.38
Commercial	53.51	1177.29
Residential	0.60	1778.93



	Direct Access	Bundled
Agricultural	0.00	0.02
Lighting	0.00	0.59
Industrial	0.30	1.49
Commercial	0.23	23.84
Residential	0.08	317.84

In California, eligibility for DA enrollment is currently limited to non-residential customers and subject to a maximum allowable annual limit for new enrollment measured in gigawatt-hours of new load and managed through an annual lottery.[20] Customers classified as taking service under DA arrangements are not included in this Plan, as it is assumed that these customers will remain with their current Energy Service Provider (ESP)[21].

SJCE Customer Participation Rates

Before customers are served by SJCE, they will receive a minimum of two notices with their monthly energy bill 60 and 30 days before SJCE's launch. These notices will provide information needed to understand the terms and conditions of service from SJCE and explain how customers can opt-out, if desired. Notices typically provide a rate comparison between the CCA and the IOU. Subsequent to commencement of service, customers will be given two additional opportunities to opt-out and return to PG&E, also provided with their monthly bills one and two months after SJCE's launch. Customers that opt-out between the initial switchover date and the close of the post enrollment opt-out period will be responsible for SJCE charges for the time they are served by SJCE but will not otherwise be subject to any charges for leaving SJCE. All customers that do not follow the opt-out process specified in the customer notices prior to launch will be

[20] S.B. 286 (CA, 2015-2016 Reg. Sess.)

[21] CPUC rulemaking to date has not addressed how vintage would be handled to DA customers that opt to switch to receive electric power from a CCA rather than their ESP. The most recent ruling on PCIA vintaging was issued on 10/5/2016: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M167/K744/167744142.PDF.

automatically enrolled into SJCE[22]. SJCE would provide a minimum of four opt-out notices to customers to notify and educate them about SJCE's product and their option to opt-out. Customers automatically enrolled will continue to have their electric meters read and billed for electric service by PG&E. SJCE bills processed by PG&E will show separate charges for power supply procured by SJCE, all other charges related to delivery of the electricity by PG&E and other utility charges that will continue to be assessed.

This Plan anticipates an overall customer participation rate of 100 percent during Phase 1, as service is being offered to municipal facilities. For non-municipal accounts added in phases 2 and 3, it is assumed that approximately 85 percent of residential customers and 75 percent of non-residential customers will remain with SJCE. These opt-out assumptions are conservative based on participation rates in other CCAs. Operating CCAs in California have experienced participation rates ranging from 86%[23] (Marin Clean Energy) to 99% (Peninsula Clean Energy). On average, 90 percent of all potential customers have stayed with their CCA.

San José Clean Energy Launch Phases

For this Plan, it is assumed that service will be offered to customers in three phases (Exhibit 5):

Exhibit 5
CCA Load, Customers, and Revenue by Phase

Phase	Start	Eligibility	Customer Accounts	Load (GWh)	Peak Demand (MW)	Operating Revenues
1	January, 2018	Municipal Facilities	1,600	74	17	$9 million
2	June, 2018	Municipal, Residential, and Small Commercial	293,000	2,013	533	$160 million
3	November, 2018	All Customers	300,000	4,015	957	$350 million

Estimates assume an 85% participation rate for residential customers and a 75% participation rate for non-residential customers. Phases 1 & 2 run five months each, so loads and revenues for those periods were normalized to a full-year period. Phase 3 loads and revenues are based on the projection for 2019. Loads are expressed as wholesale load and include 7 percent losses.

This phasing strategy enables SJCE to manage any start-up and operational issues before full scale operations are undertaken. In addition, this phasing strategy will allow SJCE's electricity suppliers, scheduling coordinators and data management entities to ramp up power supply procurement and bill processing over several months. It will also minimize bad debt expense

[22] Typically, this doesn't apply to DA customers as the CCA would assume that these customers are not interested in being served by SJCE unless otherwise confirmed prior to launching service.

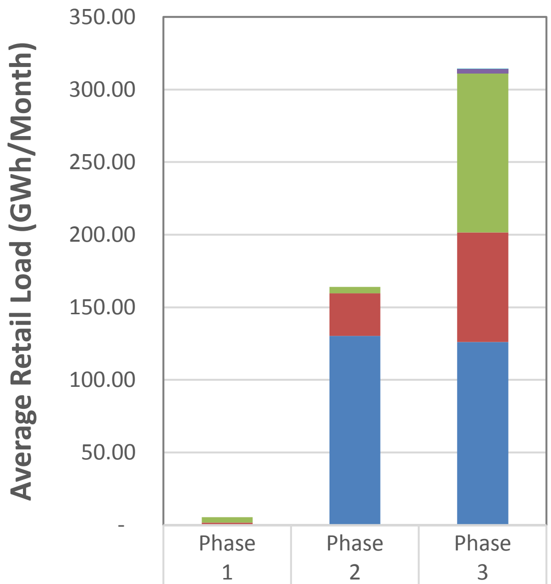
[23] MCE initially reached a 77% participation rate during its first launch phase in May of 2010, which served the first CCA customers in California. Since that time, MCE (and all other CCAs in California) have enjoyed higher participation rates. Currently, MCE's participation rate is 86%.

exposure and increase customer participation through demonstrated successful service in early phases.

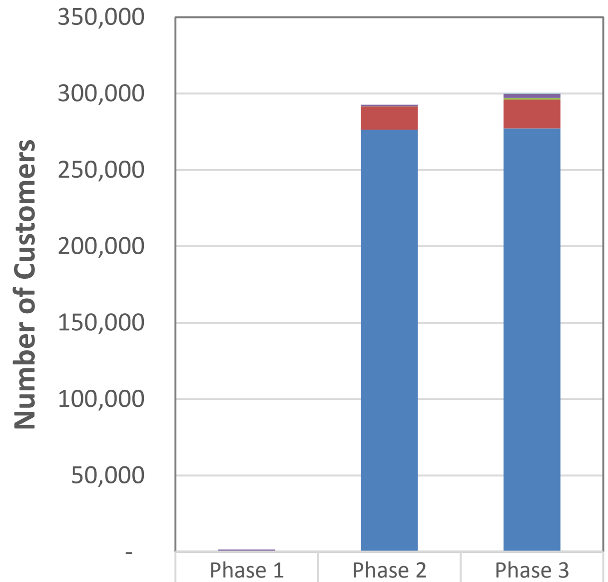
San José provided monthly energy use and peak demand data for each municipal facility for the 2015 calendar year. At the request of San José, the San José-Santa Clara Regional Wastewater Facility's load was excluded from this analysis (although it would be a SJCE customer if launched) because it is likely that it will generate or procure its own power within the first couple of years of SJCE's operations. If the facility were to participate in the CCA, its participation would only improve the financials of SJCE's initial phase so removal is just a conservative analysis approach. Moreover, if the facility were to develop an RPS-eligible power generation system on site, it could become an asset for local renewable power supply.

Data on energy use and number of customers for each phase is displayed in Exhibit 6. Exhibit 7 illustrates the historic monthly load by end-use sector for the accounts in each phase of SJCE's launch.

Exhibit 6
Load and Customers by Phase

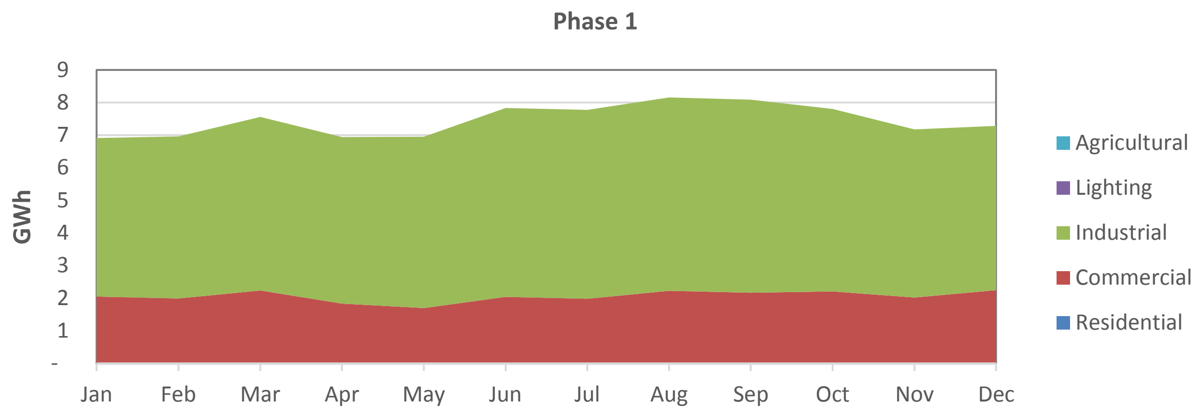


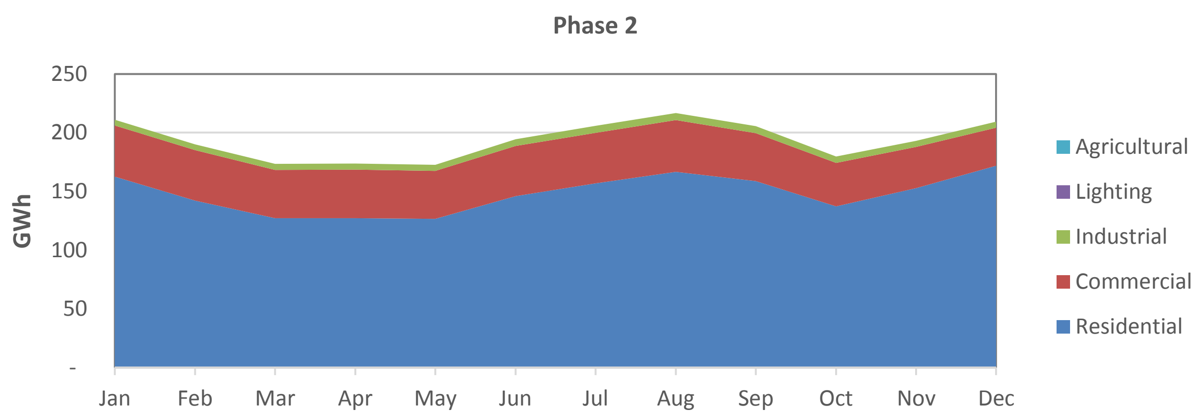
	Phase 1	Phase 2	Phase 3
Agricultural	-	-	0.10
Lighting	-	-	2.83
Industrial	3.84	4.36	109.49
Commercial	1.66	29.25	75.52
Residential	-	130.39	126.12

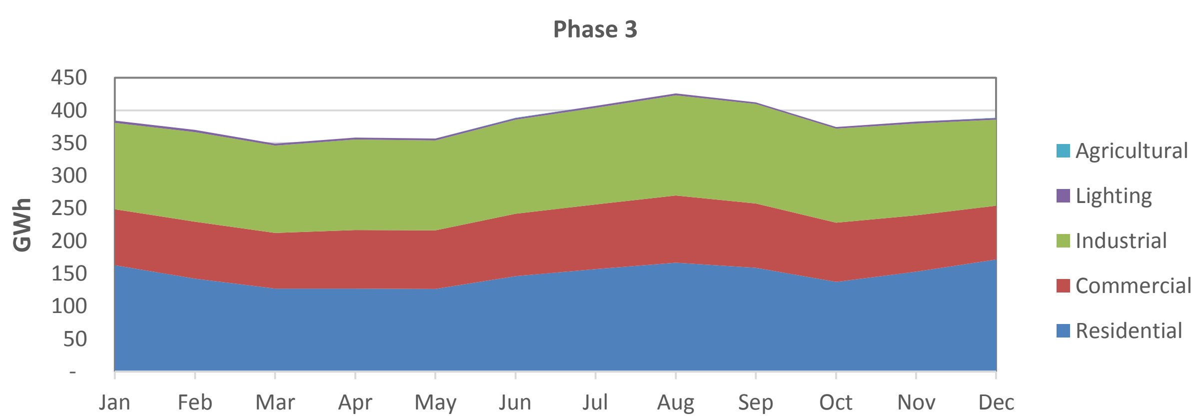


	Phase 1	Phase 2	Phase 3
Agriculture	-	-	15
Lighting	1,028	1,061	2,713
Industrial	37	40	1,182
Commercial	524	15,223	18,899
Residential	-	276,386	277,159

Exhibit 7
Historic Monthly Load of Accounts in Each Phase



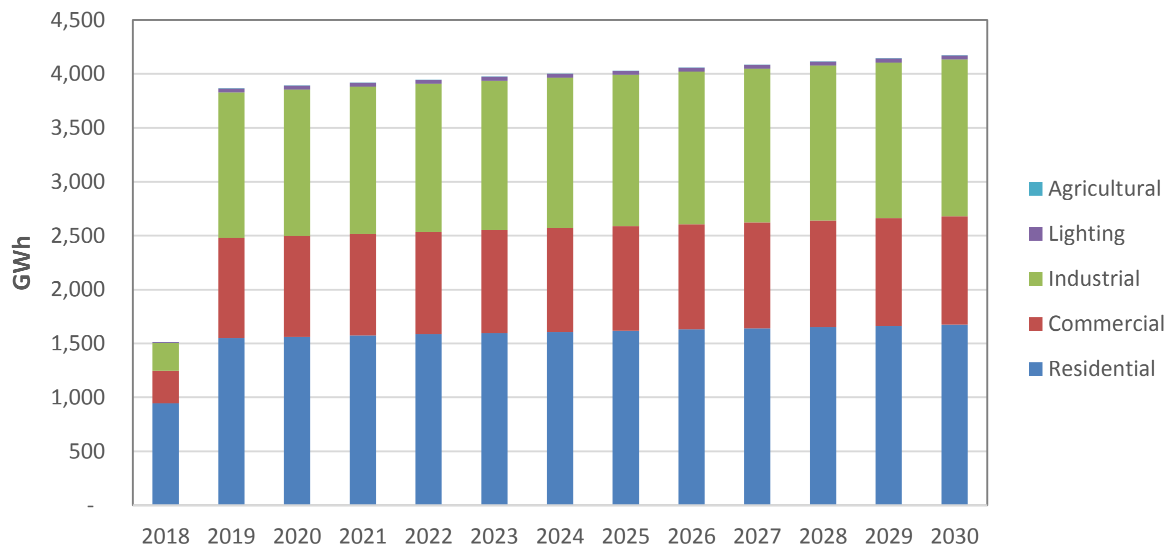




Forecast Consumption and Customers

The number of customers enrolled in SJCE and the retail energy they consume are assumed to increase at 0.7 percent per year. This forecast is based on the California Energy Commission's (CEC) mid-demand baseline forecasts for Santa Clara County.[24] Hourly electric consumption and peak demands have been estimated based on PG&E's hourly load profiles for each customer classification. The forecast of load served by SJCE over the next 20 years is shown in Exhibit 8. The SJCE forecast of GWh sales in Exhibit 9 reflects the roll-out and customer enrollment schedule shown above. Annual wholesale energy requirements are also shown below in Exhibit 9 ("Total Load" column).

Exhibit 8
Projected Load by Sector



[24] http://www.energy.ca.gov/2014_energypolicy/documents/demand_forecast_cmf/LSE_and_BA/.

Exhibit 9 SJCE Projected Annual Energy Requirements (GWh)			
Year	Retail Sales	Losses[25]	Total Load
2018	1,511	100	1,611
2019	3,865	255	4,120
2020	3,892	257	4,149
2021	3,919	259	4,178
2022	3,947	260	4,207
2023	3,974	262	4,237
2024	4,002	264	4,266
2025	4,030	266	4,296
2026	4,058	268	4,326
2027	4,087	270	4,357
2028	4,115	272	4,387
2029	4,144	274	4,418
2030	4,173	275	4,449

Resource Adequacy Requirements

In addition to determining the renewable resource requirement, SJCE will also need to demonstrate it has sufficient physical power supply capacity to meet its projected peak demand plus a 15 percent planning reserve margin. This requirement is in accordance with resource adequacy regulation administered by the CPUC, CAISO and the CEC.

The CPUC's resource adequacy standards applicable to SJCE require a demonstration one year in advance that SJCE has secured physical capacity for all of its "local requirements" in addition to 90 percent system need to cover its procurement obligation for each of the five months May through September, plus a minimum 15 percent reserve margin. On a month-ahead basis, SJCE must demonstrate 100 percent of its procurement obligation of local, system and flexible capacity products. Generally speaking, this reflects 115% of monthly demand, although the specific procurement obligation is determined by the CEC in consultation with the CAISO. The CPUC undertakes annual policy changes to the RA program, so these requirements may change some by the time full program phase-in occurs. Different types of resources had different capacity values for RA compliance purposes, and those values can change by month. Moreover, pending rule changes may have the result of reducing the RA value from wind and solar resource as more of those technologies are added to the system, so other types of renewables, such as

[25]Transmission and Distribution power losses were estimated at 6.6% based on the California Energy Commission's Public Electricity and Natural Gas Demand Forecast published 4/20/2015 at http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN204261-9_20150420T154646_Pacific_Gas_and_Electric_Company's_Notes_re_2015_IEPR_Demand_Fo.pdf.

geothermal or biomass, could have an overall better value in the portfolio than relying on RA solely from gas resources.

The Plan's load forecast estimates capacity needs, including resource capacity requirements, to be used for the power supply cost forecasting.

Power Supply Strategy and Costs

This section of the Plan discusses SJCE's resource strategy, projected power supply costs, and resource portfolios based on SJCE's projected loads.

Long-term resource planning involves load forecasting and supply planning on a 10- to 20-year time horizon. SJCE's planners will develop integrated resource plans that meet their supply objectives and balance cost, risk, and environmental considerations. Integrated resource planning also considers demand side energy efficiency, demand response programs, and traditional supply options. SJCE will require staff or a consultant to oversee planning even if the day-to-day supply operations are contracted to third parties. This staff or consultant will ensure that local preferences regarding the future composition of supply and demand resources are planned for, developed, and implemented.

Resource Strategy

SJCE is interested in maximizing the use of cost-effective renewable generation resources for its customers. SJCE can achieve this goal while offering rates that are competitive with PG&E by using tax-exempt financing to invest capital in resources such as solar and wind generating projects. Power purchases from renewable and non-renewable resources will supply the majority of the remaining power supply needs. SJCE should rely on a reputable scheduling coordinator to economically manage SJCE's power purchases and wholesale market transactions. As discussed in greater detail below, SJCE's electric portfolio will likely be managed by SJCE with input from its scheduling coordinator. The scheduling coordinator will obtain sufficient resources each hour to serve all of SJCE customer loads. The functions of a scheduling coordinator are discussed below in more detail.

Projected Power Supply Costs

This Plan evaluates the costs of renewable and non-renewable generating resources as well as power purchase agreements based on current and forecast wholesale market conditions, recently transacted power supply contracts for renewable energy, and a review of the applicable regulatory requirements.

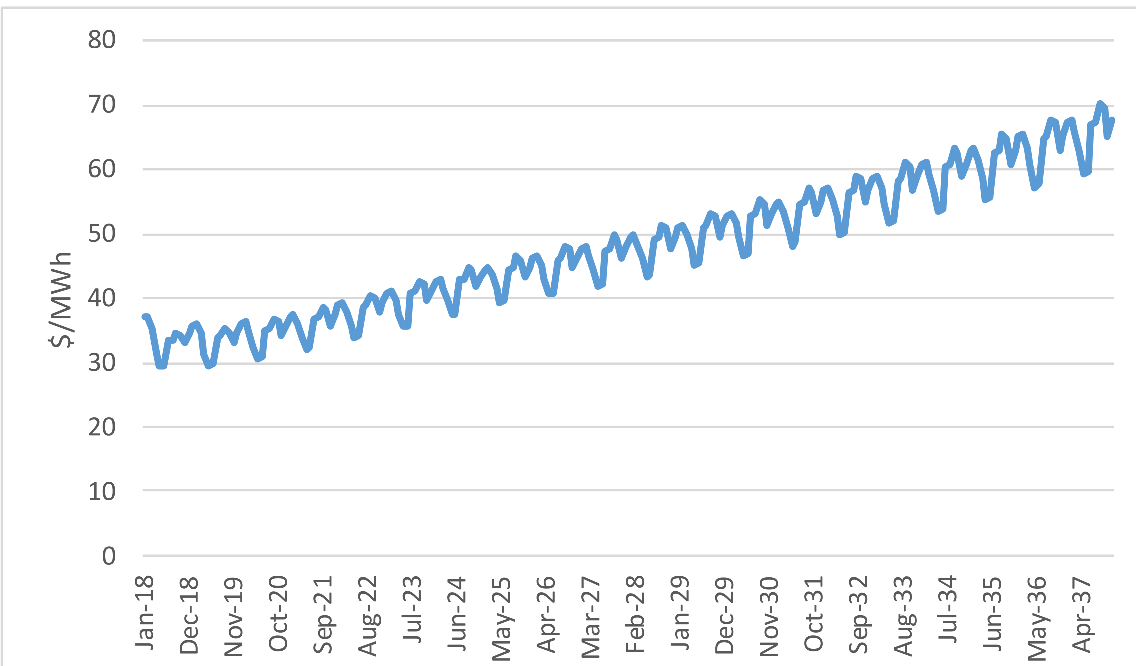
Market Purchases

Natural gas-fired power plants are typically the marginal power supply resource that sets the electricity market price in northern California and elsewhere in the Western Electricity

Coordinating Council (WECC)[26] footprint. Resources that operate on the margin only run when it is economic to do so (i.e. when the costs associated with running the resources are less than the revenue made in the wholesale market). As the market price of electricity is usually set by the cost of the marginal unit, a wholesale market price forecast has been developed using a forecast of natural gas prices and the projected relationship between gas prices and electricity prices (also defined as market-implied heat rates or spark spreads). A more detailed description of the methodology used to develop a wholesale market price forecast is included in Appendix F. Based on the methodology detailed in Appendix F, northern California wholesale market prices are projected to escalate annually at an average rate of 3.7 percent from 2018 through 2037.

Exhibit 10 shows forecast monthly northern California wholesale electric market prices. The levelized value of market prices over the 20-year study period is $46/MWh (2016$) assuming a 4 percent discount rate. The seasonal shape of electric market prices is similar to the shape of natural gas prices. Electric market prices peak in the winter and summer when there is heating and cooling load.

Exhibit 10
Forecast Northern California Wholesale Market Prices



Wholesale power prices have been used to calculate balancing market purchases and sales. When SJCE's loads are greater than its resource capabilities, SJCE's scheduling coordinator will

[26] The Western Electricity Coordinating Council promotes electric system reliability in the western interconnection and is responsible for compliance monitoring and enforcement.

schedule balancing purchases and SJCE will incur balancing market purchase costs. When SJCE's loads are less than its resource capabilities, SJCE's scheduling coordinator will transact balancing sales and SJCE will receive market sales revenue. Balancing market purchases and sales can be transacted on a monthly, daily and hourly pre-schedule basis.

Renewable Energy

The wholesale market prices shown in Exhibit 11 are for non-renewable power (i.e., this product does not come with any renewable attributes). The cost of renewable resources varies greatly. Wind and solar levelized project costs vary from $35 to $60/MWh. Geothermal project costs can vary from $70 to $100/MWh. While geothermal projects have higher cost, they also have higher capacity factors than wind and solar projects and, as such, can bring additional value to SJCE as baseload resources. Geothermal resources also bring value from a resource adequacy perspective. The availability of off-shore wind and ocean power in the marketplace is fairly minimal, so these resources were not included in the assessment of renewable energy market prices.

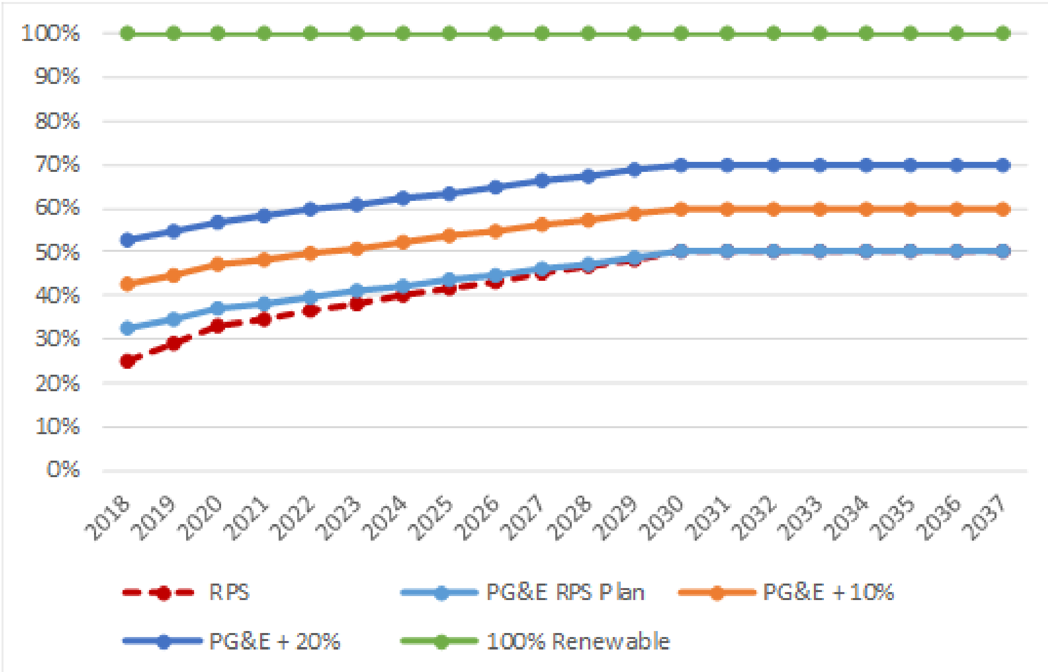
This study assumes a base case renewable energy market price of $46/MWh for a blend of wind and solar resource contracts, based on a survey of renewable resources currently in operation and new projects coming on-line. Going forward, we assume this price will remain static for the 20-year study period to balance the influence of two trends. First, renewable energy prices are being driven down by the rapidly declining cost of solar projects. This trend has persisted over the past five years and is expected to continue over the study period. However, this trend could be balanced out by the impact of increasing statewide demand for renewables as a result of California's RPS laws. These assumptions regarding renewable energy prices have been independently confirmed by current market trends? in northern California.

The amount of renewable energy purchased in the SJCE base case is assumed to be equal to the amount purchased under PG&E's renewable energy procurement plan. As shown below in Exhibit 11, PG&E's procurement plan[27] includes annual renewable energy purchases that exceed RPS requirements by only small amounts. This Plan offers three possible portfolios with greater renewable energy purchases. The first two portfolios assume renewable purchases that are 10 percent and 20 percent greater than PG&E's RPS purchases under their procurement plan. The final portfolio provides 100 percent of SJCE's power requirements with renewable energy.

Exhibit 11 shows the percent of retail load served by the four portfolios included in this study. The assumptions included in the four resource portfolios included in the Plan are discussed in more detail in the Appendix F.

[27] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M158/K845/158845742.PDF

Exhibit 11
Renewable Energy Purchase Scenarios Compared to RPS Requirements[28]



Note: The "RPS" line shown above includes inter-year targets; inter-year targets are advisory only and not required for compliance. Compliance requirements are 25 percent in 2018-19, 33 percent in 2020-23, 40 percent in 2024-26, 45 percent in 2027-29 and 50 percent beginning in 2030.

As will be discussed later in this section of the Plan, the base case price of local renewable resources is assumed to be $65/MWh. Smaller scale solar projects typically have greater costs than large scale projects.

Renewable Energy Credits (RECs)

California load serving entities must purchase bundled energy and/or renewable energy credits (RECs) that meet certain eligibility requirements across three Portfolio Content Categories (PCC) or buckets. Each of the buckets represents a different type of renewable product that can be used to meet up to a specific percent of the total procurement obligation during a compliance period. The permitted percentage shares of each bucket type changes over time. The three buckets and the type of energy included in each bucket can be summarized as follows:

[28] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M158/K845/158845742.PDF

- **Bucket 1**: Bundled renewable resources and RECs – either from resources located in California or out-of-state renewable resources that can meet strict scheduling requirements ensuring deliverability to a California Balancing Authority ("CBA");
- **Bucket 2**: Renewable resources that cannot be delivered into a CBA without some substitution from non-renewable resources[29]. This process of substitution is referred to as "firming and shaping" the energy. The firmed and shaped energy is bundled with Renewable Energy Certificates (RECs).
- **Bucket 3**: Unbundled Renewable Energy Credits (RECs), which are sold separately from the electric energy[30].

Under the current guidelines, the amount of RECs that can be procured through Buckets 2 and 3 is limited and decreases over time. SBX1 2 (April 2011) established a 33 percent RPS requirement by 2020 with certain procurement targets prior to 2020. SB350 (October 2015) increased the RPS requirement to 50 percent by 2030. The share of renewable power that can be sourced from Category 2 or 3 energy after 2020 is expected to be the same as for 2020 as a share of total RPS procurement.[31]

Historically, the Bucket 1 resources are the "premium product" and have been the most expensive type of RPS-eligible energy, so load serving entities were only procuring the minimum they need to meet the RPS requirement. However, with the decrease in solar project costs, Bucket 1 has become relatively less expensive with lower regulatory challenges compared to Buckets 2 and 3 products. Moreover, Bucket 2 products face certain potential risks due to California Air Resources Board (CARB) GHG regulatory rules which can, in some instances, impose a GHG compliance cost on the imported power.

Unbundled RECs are not viewed as good for the development of new projects. Developing or purchasing the output from new renewable resources, including resources sited within SJCE's service territory, results in new renewable projects being added to the portfolio of renewable resources in the state and an increase in the percent of energy supplied by renewable energy in the state. Purchasing unbundled RECs from existing renewable resources does not increase the amount of renewable projects in the state. In addition, the REC market is not as liquid as it once

[29] This may occur if a California entity purchases a contract for renewable power from an out of state resource. When that resource cannot fulfill the contract, due to wind or sun intermittency for example, the missing power is compensated with non-renewable resources.

[30] For example, a small business with a solar panel has no RPS compliance obligation, so they use the power from the solar panel, but do not "retire" the REC generated by the solar panel. They can then sell the REC, even though they are not selling the energy associated with it.

[31] California Public Utilities Commission Final Decision, 12/20/2016, accessed at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K457/171457580.PDF, on 1/19/2017.

was. For these reasons, the Plan does not rely on unbundled REC purchases to meet renewable energy purchase requirements under the RPS. Small quantities of unbundled RECs are used to balance SJCE's annual renewable energy purchase targets with the output from the renewable resources included in the Plan. Due to the size and shape of the renewable energy purchases, the annual modeled renewable energy purchases do not match up with annual renewable energy purchase targets down to the REC. In some years there are small REC surpluses and in some years there are small REC deficits. These surpluses and deficits are balanced out using unbundled REC purchases and sales. This methodology was used in order to simplify the modeling. In reality small REC surpluses and deficits would most likely be handled by banking RECs between years.

For the Plan's base case, unbundled REC prices are assumed to increase from $10/REC in 2018 to $20 in 2037 (3.7 percent annual escalation). Due to the decline in solar project costs (to near $40/MWh), the difference between the cost of solar projects and the cost of unbundled RECs to meet RPS requirements plus wholesale market purchases to meet load is negligible. Due to this shift in market dynamics, Bucket 3 RECs are no longer the least expensive option (as they were historically).

The Plan assumes that SJCE will not substantially rely on unbundled REC purchases to meet RPS requirements. The REC market can, however, be used to intra-adjust some RPS requirements with renewable energy acquisitions during a compliance period. If SJCE is short of RECs in a given compliance year, RECs could be purchased to meet the requirements. If SJCE has excess RECs in a given compliance year, surplus RECs could be sold. The Plan assumes that small amounts of unbundled RECs are purchased and sold each year in order to exactly match up with SJCE's annual renewable energy targets.

Transmission Congestion Costs

SJCE will pay the CAISO for transmission congestion and ancillary services. Transmission congestion occurs when there is insufficient capacity to meet the demands of all transmission customers. Congestion is managed by the CAISO by charging congestion charges in the day-ahead and real-time markets. The Grid Management Charge (GMC) is the vehicle through which the CAISO recovers its administrative and capital costs from the entities that utilize the CAISO's services. Based on a survey of GMC costs currently paid by CAISO participants, SJCE's GMC costs are expected to be near $0.5/MWh. A more detailed discussion of transmission congestion costs is included in the Appendix F of this Plan.

Ancillary Service Costs

Because generation is delivered as it is produced and particularly with respect to renewables can be intermittent, deliveries need to be firmed using ancillary services to meet SJCE's load requirements. Ancillary services and products will need to be purchased from the CAISO based on the total loads served. Based on a survey of ancillary service costs currently paid by CAISO participants, SJCE's base case ancillary service costs are estimated to be near $5/MWh, escalating by 1.5 percent annually thereafter. Serving a greater percentage of load with renewables will likely result in increased grid congestion and higher ancillary service costs. For this reason, ancillary service costs are assumed to increase with increasing amounts of renewable purchases. A more detailed discussion of transmission ancillary service costs is included in the Appendix F of this report.

Power Management/Scheduling Coordinator

Given the likely complexity of SJCE's resource portfolio, SJCE will want to rely on a reputable scheduling coordinator to economically manage SJCE's power purchases and wholesale market transactions. SJCE's resource portfolio will ultimately include market purchases, shares of some relatively large power supply projects, as well as shares of smaller, most likely renewable, resources with intermittent output. Managing a diverse resource portfolio with metered loads that will be heavily influenced by distributed generation will be one of the most important functions of SJCE. As such, SJCE needs a dependable, established scheduling coordinator with a proven track record in the industry. SJCE's scheduling coordinator will be one of its most important business partners.

SJCE should initially contract with a third-party with the necessary experience (and balance sheet) to perform most of SJCE's portfolio operation requirements. This will include the procurement of energy and ancillary services, scheduling coordinator services, and day-ahead and real-time trading. Portfolio operations encompass the activities necessary for wholesale procurement of electricity to serve end use customers. These activities include the following:

- *Electricity Procurement* – assemble a portfolio of electricity resources to supply the electric needs of SJCE customers.

- *Risk Management* – standard industry risk management techniques will be employed to reduce exposure to the volatility of energy markets and insulate customer rates from sudden changes in wholesale market prices.

- *Load Forecasting* – develop accurate load forecasts, both long-term for resource planning, and short-term for the electricity purchases and sales needed to maintain a balance between hourly resources and loads.

- *Scheduling Coordination* – scheduling and settling electric supply transactions with the CAISO, with related back office functions to confirm PG&E billing to customers.

SJCE should approve and adopt a set of protocols that will serve as the risk management tools for SJCE and any third-party involved in SJCE portfolio operations. Protocols will define risk management policies and procedures, and a process for ensuring compliance throughout the organization. During the initial start-up period, the chosen full requirements electric suppliers will bear the majority of risks and be responsible for their management. The protocols that cover electricity procurement activities should be developed before operations begin, however, the protocols may need to be refined as lessons are learned during the first few months of operations.

A scheduling coordinator provides day-ahead and real-time power and transmission scheduling services. Scheduling coordinators bear the responsibility for accurate and timely load forecasting and resource scheduling including wholesale power purchases and sales required to maintain hourly load/resource balances. A scheduling coordinator needs to provide the marketing expertise and analytical tools required to optimally dispatch SJCE's surplus resources on a monthly, daily, and hourly basis.

SJCE's scheduling coordinator will need to forecast SJCE's hourly loads as well as SJCE's hourly resources including shares of any hydro, wind, solar, and other resources in which SJCE is a participant/purchaser. Forecasting the output of hydro, wind, and solar projects involves more variables than forecasting loads. Scheduling coordinators already have models set up to accurately forecast hourly hydro, wind, and solar generation. Accurate load and resource forecasting will be a key element in assuring SJCE's power supply costs are minimized.

A scheduling coordinator also needs to provide monthly checkout and after-the-fact reconciliation services. This requires scheduling coordinators to agree on the amount of energy purchased and/or sold and the purchase costs and/or sales revenue associated with each counterparty with which SJCE transacted in a given month. A more detailed discussion of scheduling coordinator services is included in the Appendix F of this report.

Based on conversations with scheduling coordinators currently working the CAISO footprint, the estimated cost of scheduling services is in the $1 to $2/MWh range. The Plan assumed a cost of $1.5/MWh, escalating at 2 percent annually, in all portfolios.

Resource Portfolios

We discuss four representative resource portfolios to develop pricing estimates for SJCE customers. Portfolios are defined on two variables: (1) the share of renewable energy in the power mix, and (2) the share of resources that are GHG-free in the power mix. Renewable resources refer to resources that qualify under State and Federal RPS, such as solar and wind power. GHG-free power refers to energy sourced from any non-GHG emitting resource, including both the RPS-compliant sources mentioned above as well as nuclear power and large hydroelectric power.

Because SJCE's power products will compete with those of PG&E's, we define each portfolio based on how it compares to PG&E's base power product. At present, PG&E's power supply is 30% renewable and 59% GHG-free[32]. We use PG&E's 2015 Renewable Energy Procurement Plan[33] as the basis for PG&E's share of renewable and GHG-free power going forward through

[32]https://www.pge.com/pge_global/common/pdfs/your-account/your-bill/understand-your-bill/bill-inserts/2016/11.16_PowerContent.pdf

[33] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M158/K845/158845742.PDF

the study's forecast period. It is assumed that SJCE would not modify its RPS or GHG-free achievement to match unexpected or abrupt changes in PG&E's portfolio.

The four portfolios are:

- **PG&E RPS**: SJCE will match PG&E on both renewable and GHG-free energy sources.
- **PG&E RPS + 10%**: SJCE will exceed PG&E's renewable and GHG-free generation by 10%
- **PG&E RPS + 20%**: SJCE will exceed PG&E's renewable and GHG-free generation by 20%
- **100% Renewables**: SJCE will supply 100% of retail load with renewable power[34].

Portfolio 4 is designed to determine rates for customers choosing a 100 percent renewable portfolio.

Resource Options

For each of the resource portfolios, a combination of resources has been assumed in order to meet the renewable energy target, resource adequacy targets, and ancillary and balancing requirements. <u>The mix of resources included in each portfolio are for indicative purposes only</u>. SJCE should be flexible in its approach to obtaining the renewable and non-renewable resources necessary to meet these requirements.

Exhibit 12 shows the 20-year levelized resource costs used in this Plan.

[34] This scenario is modeled to develop potential pricing for customers seeking to purchase 100% renewable power from SJCE.

Exhibit 12
20-Year Base Case Levelized Resource Costs
(2016 $/MWh)

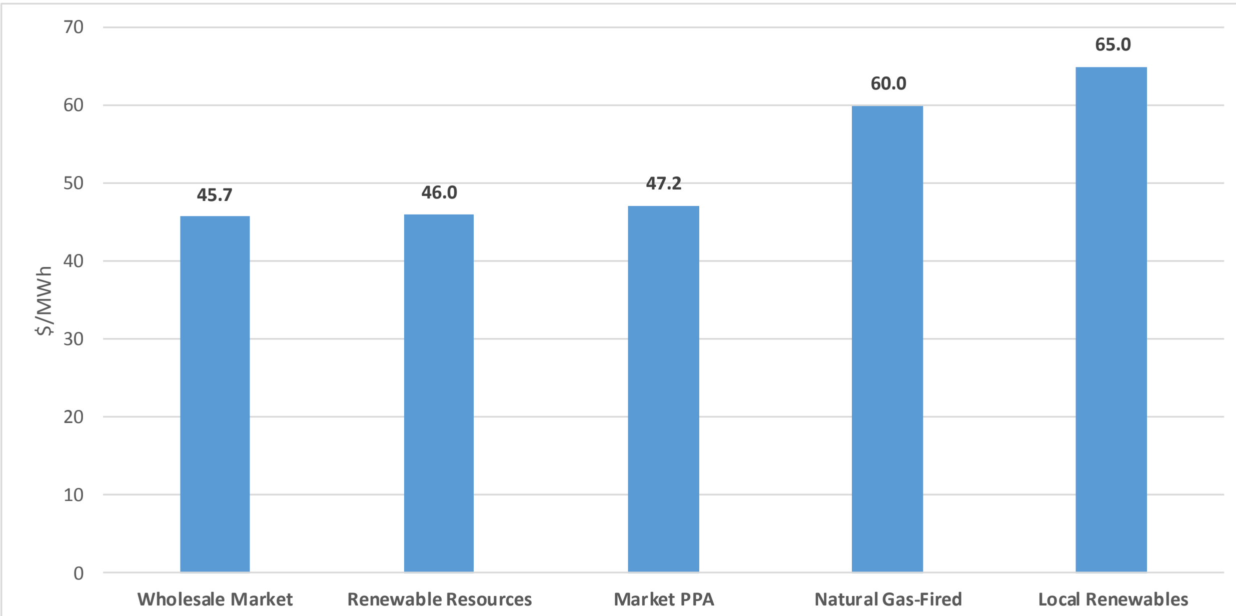


Exhibit 12 above includes both spot wholesale market and market power purchase agreement (PPA) costs. It is assumed that the wholesale market power costs are primarily for natural gas resources. Market PPA costs are greater than spot wholesale market costs in recognition of the cost of the PPA supplier absorbing the market fuel price risk associated with providing a long-term PPA contract price.

The capacity factor for market PPA purchases is assumed to be 100 percent (flat monthly blocks of power). Capacity factor is equal to average monthly generation divided by maximum hourly generation in a given month. A 100 percent capacity factor implies that the same amount of power was purchased or generated each hour. The average monthly capacity factor for renewable resources and local renewables is assumed to be 33 percent based on the capacity factors of existing renewable resources operating in the region. The capacity factor for non-renewable resources is assumed to be 80 percent.

As shown above, the base case 20-year levelized cost of renewable resources is comparable to the 20-year levelized cost of market purchases. The cost of solar projects has declined significantly over the past few years. The $46/MWh projection is based on the cost of relatively new wind and solar projects that reflect the decreased costs, on a $/watt basis, of solar projects and the extension of the federal Production Tax Credit (PTC) and the federal Investment Tax Credit (ITC). The PTC is set to expire in 2019 while the ITC, which is available to utility scale solar projects, will ramp down from 30 percent in 2019 to 10 percent in 2022 where it will remain.

Even with the ramp down of the ITC solar project costs are expected to continue to decrease in future years[35].

On a $/watt basis, the cost of smaller scale solar projects is greater than the cost of large scale solar projects. The $65/MWh cost associated with local renewables reflects this trend. The advantage of local renewable projects is lower transmission costs and less stress on the congested transmission grid.

The base case 20-year levelized natural gas cost included above in Exhibit 12 is based on projected natural gas prices and a survey of non-fuel variable and fixed costs associated with natural gas plants currently operating in the region.

Portfolio 1: Match PG&E's Renewable Resource Procurement Plan (Baseline Portfolio, Similar to Current PG&E Resource Mix)

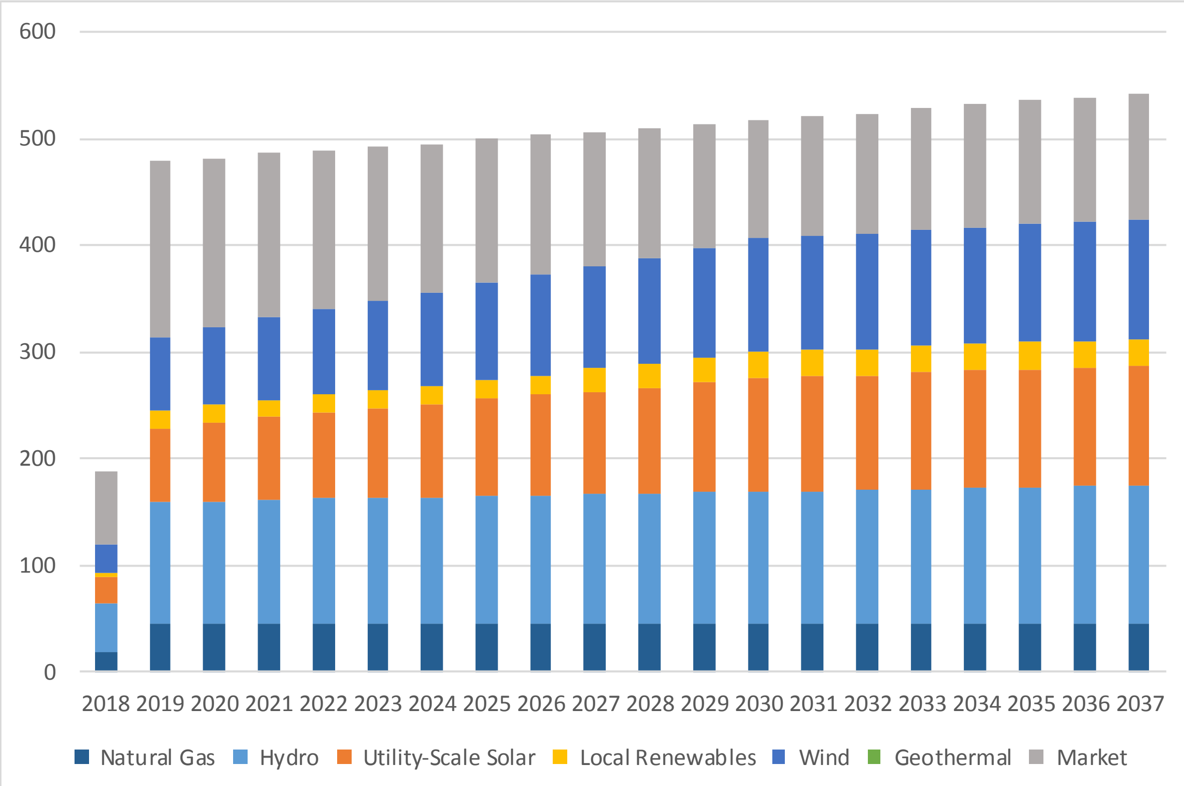
In the first portfolio, SJCE will match PG&E's estimated renewable resource procurement plan shown below:

- 2018: 33 percent
- 2018: 35 percent
- 2020: 37 percent
- 2021: 38 percent
- 2022: 40 percent
- 2023: 41 percent
- 2024: 42 percent
- 2025: 44 percent
- 2026: 45 percent
- 2027: 46 percent
- 2028: 47 percent
- 2029: 49 percent
- 2030: 50 percent

As shown above, due to the decrease in the cost of solar projects, the projected cost of renewables is comparable to the cost of market power and less than the cost of greenfield non-renewable resources (e.g., natural gas fired generation). Exhibit 13 shows the power supply portfolio used to serve load in Portfolio 1.

[35] Page 4 of "On the Path to Sunshot: Executive Summary", Solar Technologies Office, U.S. Department of Energy, https://energy.gov/sites/prod/files/2016/05/f31/OTPSS%20-%20Executive%20Summary-508.pdf

Exhibit 13
Portfolio 1: Match PG&E's Renewable Resource Procurement Plan (aMW)



*Average annual megawatt or aMW is equal to annual megawatt-hours divided by the number of hours in a year.

The share of renewable energy increases each year along with California's RPS requirements. The costs associated with this portfolio could be reduced if it was assumed that more power was purchased from market PPAs instead of non-renewable (natural gas-fired) resources. The percent of non-renewable energy purchased via market PPAs, as opposed to natural gas-fired resources, is the same in each of the three portfolios.

The source of the "market" purchases shown above in Exhibit 13 is unspecified. These market purchases could ultimately be sourced to a mix of renewable and non-renewable resources based on the availability of surplus resources in the region and resources bid into CAISO for balancing energy purchases. For study purposes, "market" purchases are assumed to be sourced to non-renewable generating facilities.

The "hydro" purchases shown above in Exhibit 13 are market purchases that are sourced to hydroelectric generating facilities. These "hydro" purchases would be procured through long-term PPAs. The cost of hydro power is assumed to be greater than the cost of unspecified market purchases. The premium applied to the cost of hydro power is discussed below in the "Greenhouse Gas Emissions" section.

The percentage of non-renewable energy purchased from the more expensive natural gas-fired resources is the same in all portfolios. In all four portfolios, approximately 15 percent of non-renewable energy is purchased from natural gas-fired resources, which have a base case 20-year levelized cost of $60/MWh. In all four portfolios, 85 percent of non-renewable energy is purchased at the lower $47.2/MWh levelized cost associated with market PPA purchases.

Likewise, the percentage of renewable energy purchased from the more expensive local renewables is the same as in Portfolio 1. In all four portfolios, approximately 10 percent of renewable energy is purchased from local renewable resources, which have a base case 20-year levelized cost of $65/MWh. In all four portfolios, 90 percent of renewable energy is purchased at the lower costs associated with large scale wind and solar projects.

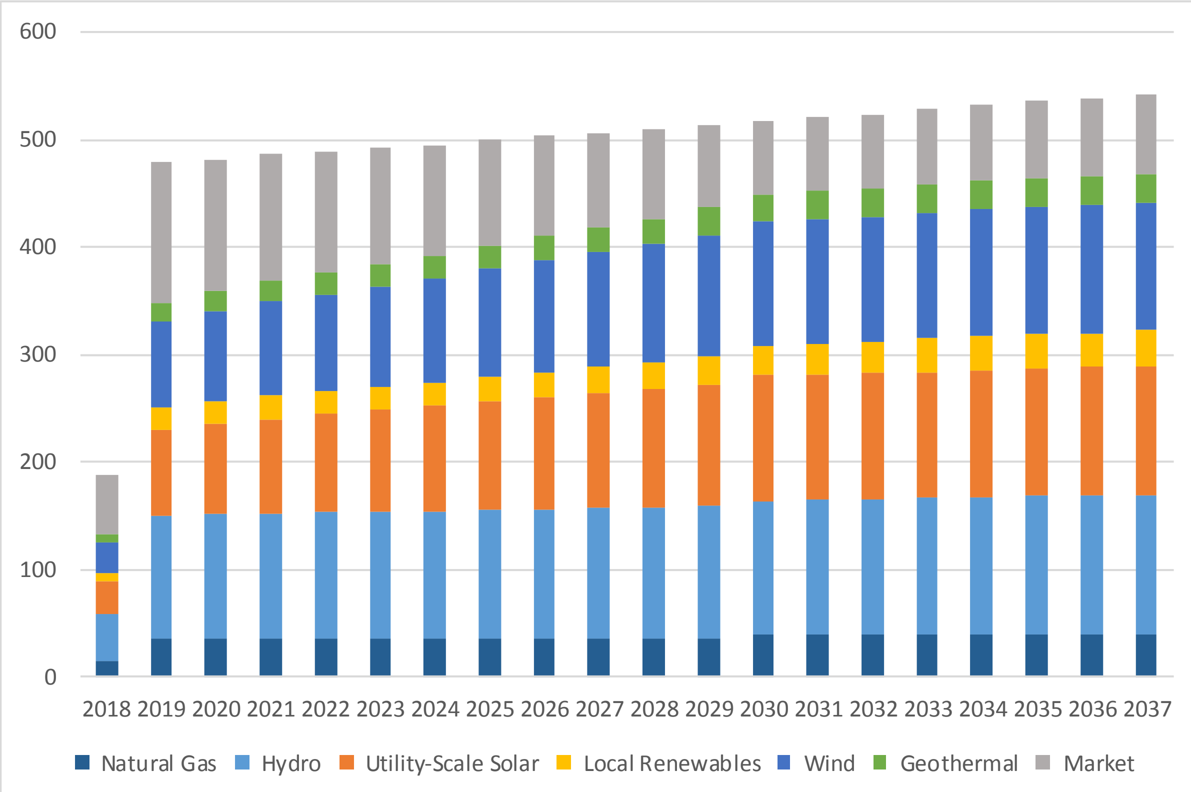
Portfolio 2: Exceed PG&E Renewable Resource Procurement Plan by 10% Each Year

In the second portfolio, SJCE will exceed PG&E's estimated renewable resource procurement plan and thus, the procurement plan included in Portfolio 1, by 10 percent each year as shown below:

- 2018: 43 percent
- 2019: 45 percent
- 2020: 47 percent
- 2021: 48 percent
- 2022: 50 percent
- 2023: 51 percent
- 2024: 52 percent
- 2025: 54 percent
- 2026: 55 percent
- 2027: 56 percent
- 2028: 57 percent
- 2029: 59 percent
- 2030: 60 percent

As shown below in Exhibit 14 the green bars showing geothermal renewable energy purchases increased compared to those shown above in Exhibit 13.

Exhibit 14
Portfolio 2: Exceed PG&E's Renewable Resource Procurement Plan by 10% (aMW)



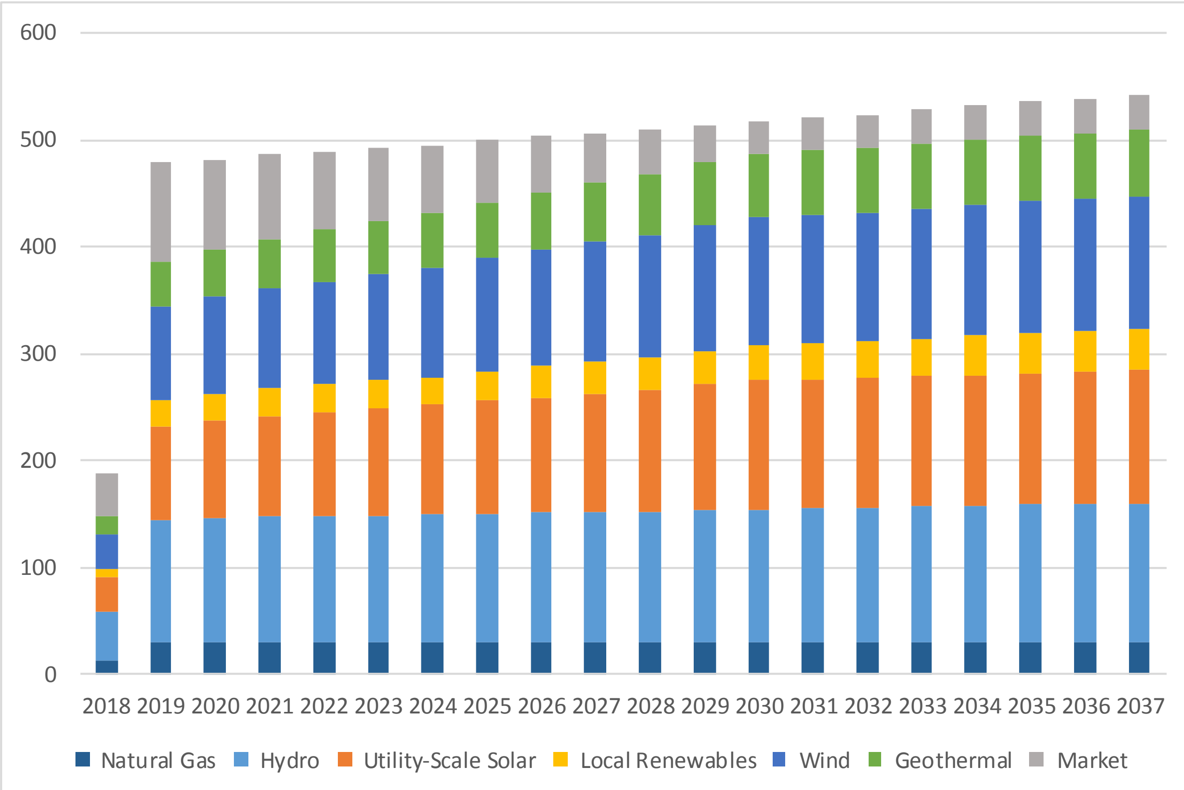
Portfolio 3: Exceed PG&E Renewable Resource Procurement Plan by 20% Each Year

In the third portfolio, SJCE will exceed PG&E's estimated renewable resource procurement plan by 20 percent as shown below:

- 2018: 53 percent
- 2019: 55 percent
- 2020: 57 percent
- 2021: 58 percent
- 2022: 60 percent
- 2023: 61 percent
- 2024: 62 percent
- 2025: 64 percent
- 2026: 65 percent
- 2027: 66 percent
- 2028: 67 percent
- 2029: 69 percent
- 2030: 70 percent

As shown below in Exhibit 15 the green bars showing geothermal renewable energy purchases increased compared to those shown above in Exhibits 13 and 14.

Exhibit 15
Portfolio 3: Exceed PG&E's Renewable Resource Procurement Plan by 20% (aMW)



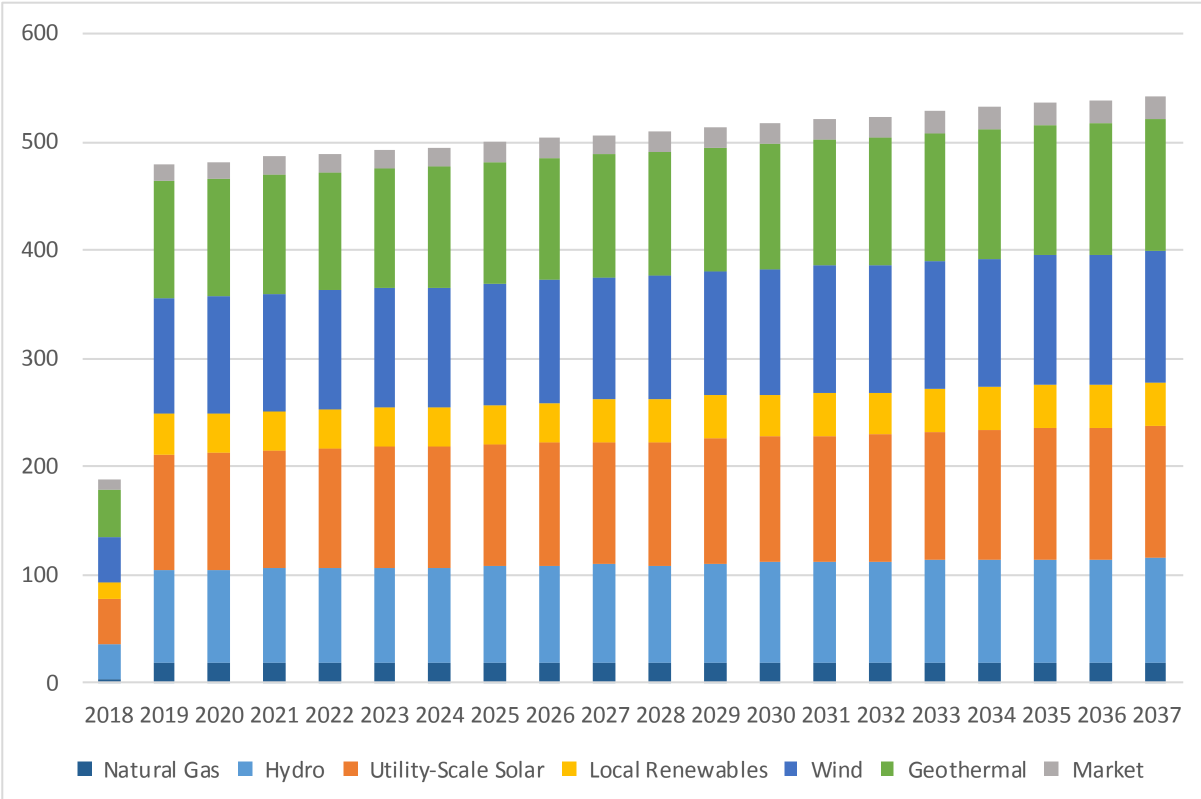
Portfolio 4: Serve 100% of Retail Load with Renewables

The renewable energy requirements in the State's RPS are based on retail energy sales. Retail energy refers to the amount of energy sold to customers as opposed to the amount of energy purchased from generation sources (wholesale energy). Wholesale energy purchases must always exceed retail energy sales to account for transmission and distribution losses.

To be consistent, it was assumed that the 100 percent renewable energy target would only apply to retail energy sales. The same concept applies to Portfolios 1, 2, and 3. For example, renewable energy purchases in Portfolio 3 are equal to 70 percent of projected retail energy sales beginning in 2030.

In the 100% renewable portfolio, retail loads are served entirely with renewable energy purchases. The difference between retail and wholesale load is met with natural gas and market PPAs. These purchases are compensated for through the purchase of renewable energy credits (RECs). Achieving 100 percent of wholesale load with renewables would be financially unviable due to the huge need for solar capacity to meet Winter loads and the enormous resulting surplus that would yield in the Summer. Exhibit 16 below shows the resource mix used to serve load in Portfolio 4.

Exhibit 16
Portfolio 4: Serve 100% of Retail Load with Renewables (aMW)



There is a significant amount of market PPA and natural gas-fired generation included in Portfolio 4 due to the mismatch between seasonal solar generation and seasonal loads. Solar generation is relatively low in winter months and peaks during summer months. Loads are also lower in the winter and higher in the summer. However, beginning in March solar generation ramps up faster than loads. This could put utilities in a position of having to find a market for relatively large amounts of surplus energy during the months of March through June when market prices are typically the lowest. Many utilities and generators will likely be surplus in the spring because of the mismatch between seasonal solar generation and loads in the spring. In addition, utilities and generators located in the Northwest also have surplus energy in the spring due to increased hydroelectric generation (due to melting snow) and wind. Non-renewable resources are included in Portfolio 4 in order to reduce SJCE's exposure to low market prices during periods in which there is an abundance of surplus energy available in the region.

Non-renewable resources are needed in Portfolio 4 to serve load during hours when renewable resources are not capable of generating power (e.g., when the wind is not blowing or the sun is not shining). Purchasing large amounts of renewable generation, as in Portfolio 4, will likely result in over-supply in on-peak hours when solar projects are generating power and under-supply in off-peak hours when solar projects are not generating. As such, during some periods, on-peak energy may need to be exchanged for off-peak energy. The cost of exchanging or firming some of the solar generation into off-peak blocks of energy is reflected in higher ancillary service costs in Portfolio 4.

Greenhouse Gas-Free Resources

PG&E's resource portfolio currently includes non-renewable energy purchases, renewable energy purchases as well as other non-greenhouse gas (GHG) emitting resources, primarily nuclear and large hydroelectric resources. PG&E has stated that 59 percent[36] of the resources currently serving load do not emit GHGs. This includes 30 percent from renewable resources, 6 percent from large hydro and 23 percent from nuclear resources. Between 2016 and 2018 (the first year of the 20-year study period in this Plan), PG&E plans to increase its renewable resource purchases by 4.5 percent, from 28 percent to 32.5 percent[37]. Since PG&E's renewable resources, which are GHG-free resources, will increase by a minimum of 4.5 percent between 2016 and 2018, the percentage of load served by GHG-free resources will also increase by 4.5 percent. As such, it is projected that 63.5 percent of PG&E's load will be served by GHG-free resources in 2018.

Last August, PG&E requested approval from the California Public Utilities Commission (CPUC) to retire the Diablo Canyon Power Plant (DCPP), PG&E's only nuclear power generating station[38], by 2025. PG&E's plan would replace the lost generating capacity (roughly 23 percent of all PG&E load[39]) with a mix of energy efficiency and renewable power. The plan would leave PG&E to select whatever mix of the two resource types is cheapest at the time. For the purposes of this plan, we assume all power used to replace DCPP will be GHG-free and that PG&E will continue to reduce GHG emissions over that period. In Portfolio #1 ("Match PG&E"), the Plan will assume that 63.5 percent of SJCE load is served by GHG-free resources in 2018. As the amount of load served by renewable resources increases each year, so too will the amount of load served by GHG-free resources. This is true of all four portfolios included in the Plan. Exhibit 17 below shows the amount of load served by GHG-free resources in 2018 through 2037 for the four portfolios.

---

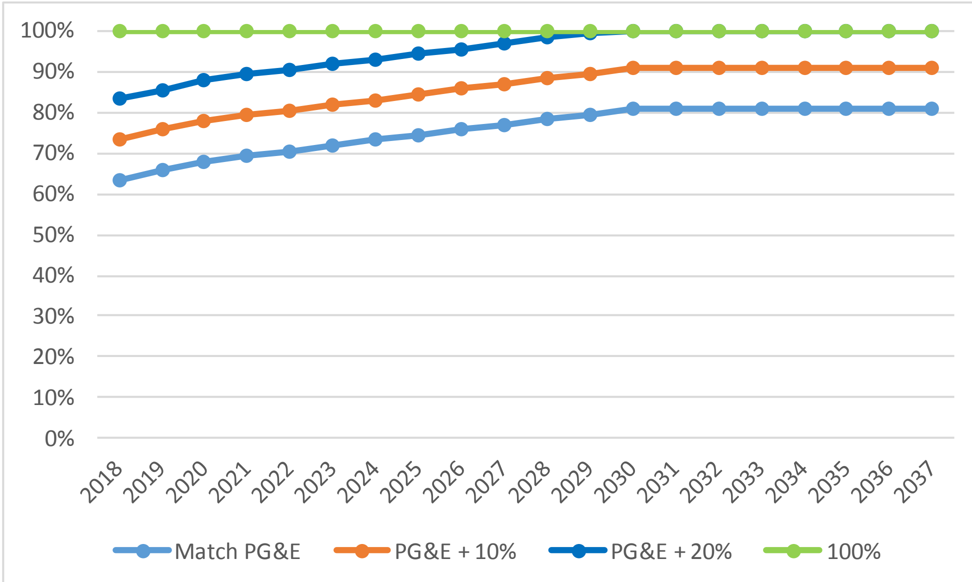
[36] PG&E's 2015 Power Mix: https://www.pge.com/pge_global/common/pdfs/your-account/your-bill/understand-your-bill/bill-inserts/2016/11.16_PowerContent.pdf

[37] PG&E 2015 Renewable Energy Procurement Plan: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M158/K845/158845742.PDF

[38] "Application of Pacific Gas and Electric Company (u 39 e) for approval of the retirement of diablo canyon power plant, implementation of the joint proposal, and recovery of associated costs through proposed ratemaking mechanisms." Accessed on 10/18/2016 at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M166/K001/166001245.PDF

[39] PG&E website, accessed 10/18/2016 at: https://www.pge.com/en_US/about-pge/environment/what-we-are-doing/clean-energy-solutions/clean-energy-solutions.page

Exhibit 17
Percent of Load Served by Greenhouse Gas-Free Resources[40]



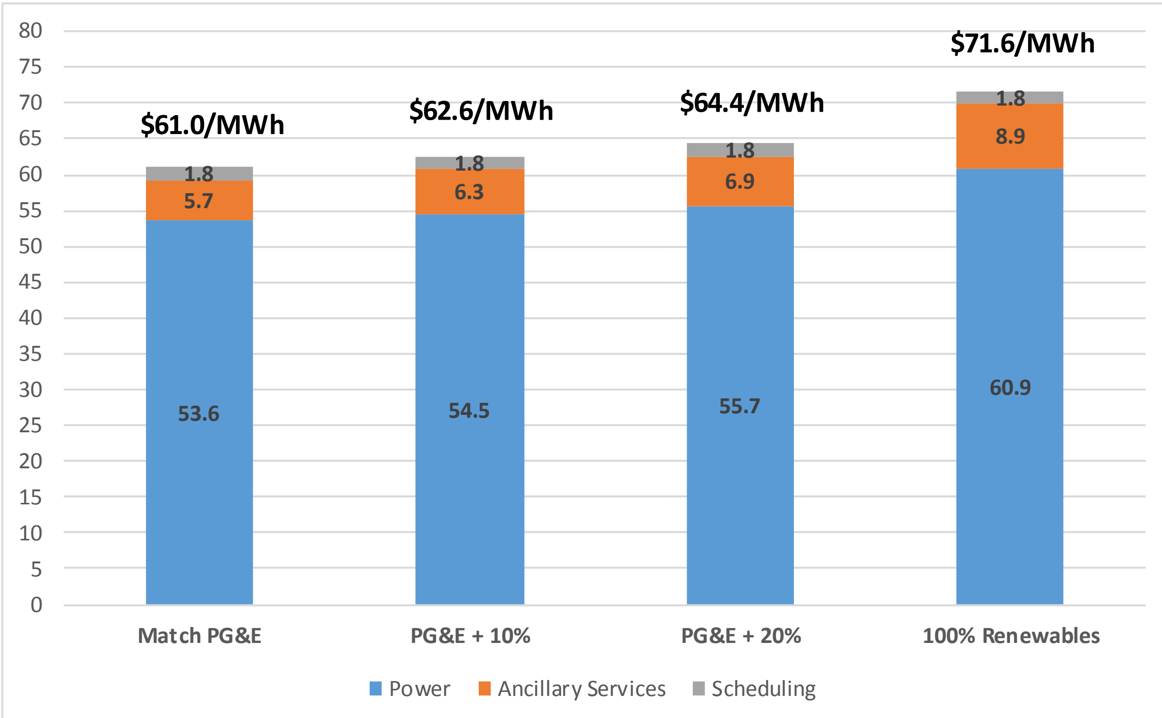
In order to achieve the GHG-free targets shown above, it was assumed that a portion of the "Market PPA" purchases shown above in Exhibits 13 through 16 are sourced to GHG-free resources and that SJCE pays a premium, above wholesale market prices, for market PPAs sourced to GHG-free resources. A calendar year (CY) 2018 premium of $6/MWh was calculated based on an assumed CY 2018 carbon price of $15/ton and a carbon dioxide emissions rate of 900 lbs./MWh, or the approximate heat rate of a typical natural gas fired generating plant. The carbon price is assumed to escalate annually by 3.75 percent, the same escalation rate applied to wholesale market prices. Given the assumed escalation rate, the premium paid for GHG-free power increases from $6/MWh in 2018 to $12/MWh in 2037. Including GHG-free premiums in the costs associated with a portion of market PPA purchases results in a $1.5 to $2/MWh increase in the 20-year levelized cost of each portfolio. Again, the portion of market PPAs that are sourced to GHG-free resources in each portfolio is based on the difference between the GHG targets (shown above in Exhibit 17) and the amount of renewable energy procured in each portfolio.

20-Year Levelized Portfolio Costs

The 20-year levelized costs have been calculated based on the base case assumptions detailed above regarding resource costs and resource compositions under the four portfolios. Exhibit 18 shows a breakdown of power, ancillary service and scheduling costs associated with each portfolio.

[40] http://www.pgecurrents.com/2016/04/25/infographic-power-mix-2015/

Exhibit 18
20-year Levelized Base Case Portfolio Costs ($/MWh)



As shown above, power costs under Portfolios 1, 2, and 3 are fairly similar. There is not a large variance in power costs between these portfolios because the majority of power is supplied by market PPAs and renewable energy purchases, which are very close in cost. Exhibit 12 shows that the base case projected 20-year levelized cost of renewables is $46/MWh while the projected 20-year levelized cost of market PPA purchases is $47.2/MWh. While the 20-year levelized cost of market PPA purchases is greater than the 20-year levelized cost of renewables, market PPA purchase prices (excluding GHG-free premiums) are assumed to escalate from $34/MWh in 2018 to $69/MWh in 2038. Based on the pricing included in recent PPAs for renewable energy, the price of renewables is assumed to be flat in all years. As such, the price of renewables in Portfolio 1 is greater than the price of a market PPA in 2018 through 2026. Because the cost for renewables is assumed to be higher in Portfolio 2, the price of renewables is greater than the price of a market PPA in 2018 through 2027, or for one additional year.

Total costs under Portfolio 4 are approximately $7/MWh greater than Portfolio 3. The costs of renewables have been assumed to be approximately $9/MWh greater in Portfolio 4 than in Portfolio 1 in recognition of the need for a more diverse mix of renewable resources. This translates into greater power costs (the blue bar) in Portfolio 4.

Each portfolio assumes that 15 percent of non-renewable energy is purchased from natural gas-fired resources with a projected 20-year levelized cost of $60/MWh. However, since more non-renewable energy is purchased in Portfolio 1, it has the highest percentage of natural gas-fired resource purchases. In Portfolio 1, 9 percent of all power purchases (renewable and non-renewable) are natural gas-fired resource purchases, compared to 7 percent in Portfolio 2, 6 percent in Portfolio 3 and 4 percent in Portfolio 4.

Sensitivity Analysis on Local Renewables

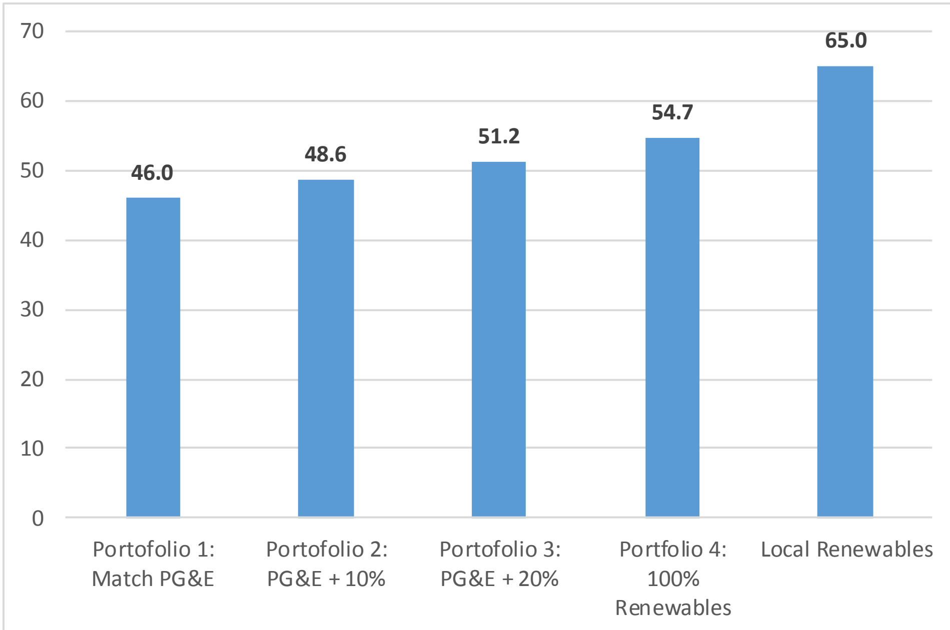
This section examines the impact of increasing the amount of local renewable power included in the Plan to 10 percent of retail load in all portfolios. The Plan assumes that "local renewable" power is primarily composed of smaller scale solar projects constructed in SJCE's service territory. On a $/watt basis, the cost of small-scale solar projects is greater than the cost of larger, utility-scale solar projects. The Plan assumes a base case 20-year levelized cost of $65/MWh cost for local renewables compared to a base case 20-year levelized cost of $46/MWh for utility-scale renewable resources. The advantage of local renewable projects over utility-scale projects is lower transmission costs and less stress on the congested transmission grid.

The $46/MWh cost assumes that 50 percent of all renewable energy purchases will be provided by utility-scale solar projects and 50 percent will be provided by wind projects. The $46/MWh projection is based on the cost of relatively new wind and solar projects and reflects the decreased costs, on a $/watt basis, of solar projects and the extension of the Federal production tax credit.

In Portfolios 2 ("PG&E + 10%") and 3 ("PG&E + 20%") it is assumed that 10 and 20 percent of "renewable resources" will be met with more expensive geothermal projects resulting in higher 20-year levelized renewable resource costs of $48.6/MWh and $51.2/MWh, respectively. The remaining 90 and 80 percent, respectively, of renewables is split evenly between utility-scale solar and wind projects. In portfolio 4 ("100% Renewables") it is assumed that renewable energy purchases are split equally between utility-scale solar, wind and geothermal projects, resulting in a 20-year levelized renewable resource cost of $54.7/MWh.

Exhibit 19 below shows the assumed 20-year levelized costs of renewable resources in portfolios 1 through 4 as well as the assumed 20-year levelized cost of local renewables.

Exhibit 19
20-Year Base Case Levelized Renewable Resource Costs
(2016 $/MWh)

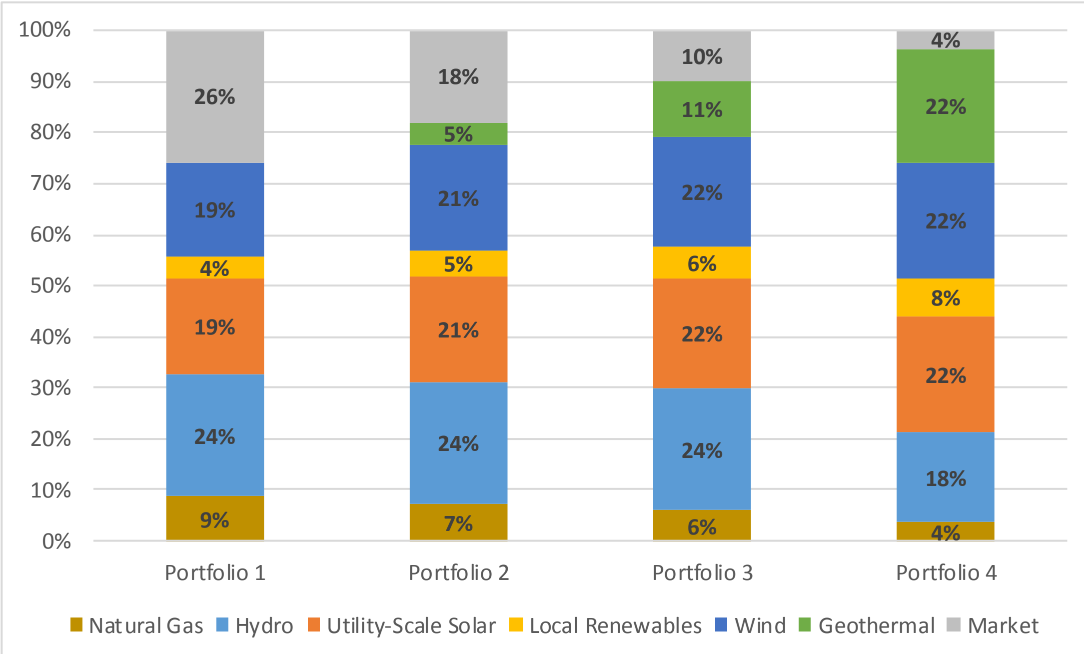


Portfolio 1 renewable resource costs include 50% solar and 50% wind.
Portfolio 2 renewable resource costs include 45% solar, 45% wind and 10% geothermal.
Portfolio 3 renewable resource costs include 40% solar, 40% wind and 20% geothermal.
Portfolio 4 renewable resource costs include 33% solar, 33% wind and 33% geothermal.

As shown above the difference between the cost of utility-scale renewable resources in portfolio 1 ($46/MWh) and the cost of local renewables ($65/MWh) is $19/MWh. The difference between the cost of utility-scale renewable resources in portfolio 4 ($54.7/MWh) and the cost of local renewables ($65/MWh) is only $10.3/MWh. As such, increasing the amount of local renewables will have a greater impact on the portfolio 1 than portfolio 4.

As noted above, in all four portfolios it was assumed that approximately 10 percent of renewable energy is purchased from local renewable resources. However, since more renewable energy is purchased in Portfolios 2, 3, and 4 than Portfolio 1, Portfolio 1 had the least amount of load served by local renewable resources. Exhibit 20 below shows a breakdown of the resources included in each portfolio.

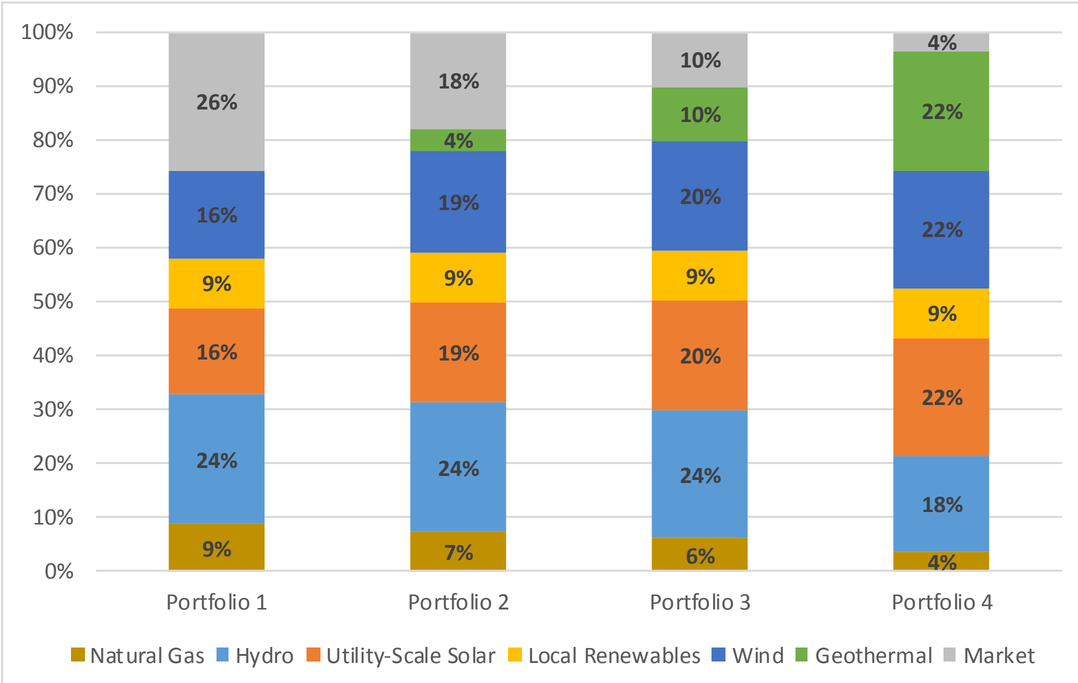
Exhibit 20
Breakdown of Total Purchases over 20-Year Period 2018-37 - Base Case Portfolios



As shown above, only 4 percent of purchases in portfolio 1 comes from local renewables compared to 8 percent in Portfolio 4. As such, increasing the amount of local renewables included in each portfolio so that 10 percent of retail load is served by local renewables will have a greater impact on portfolio 1 than Portfolio 4.

Exhibit 21 below shows the breakdown of the resources included in each portfolio if the amount of local renewables purchased is increased such that it is equal 10 percent of annual retail sales.

Exhibit 21
Breakdown of Total Purchases over 20-Year Period 2018-37 with Local Renewable Purchases Equal to 10% of Retail Sales in all Portfolios

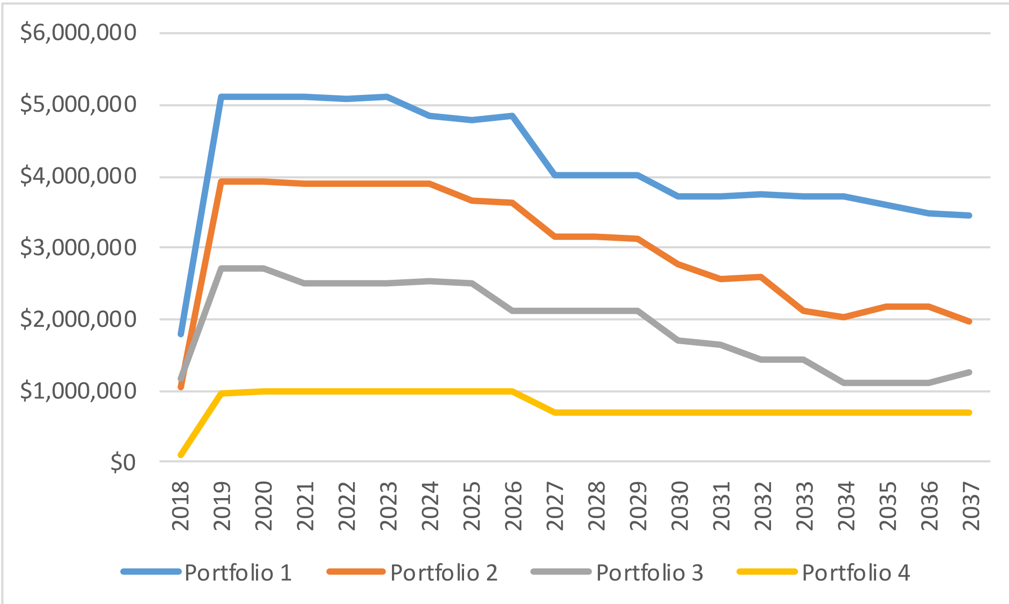


Note: 9% of total purchases is equivalent to 10% of total retail sales.

Exhibit 21 shows "local renewables", and all other resources, as percentages of total power purchases. As indicated in the note below Exhibit 20, "local renewables" are 9 percent of total power purchases but 10 percent of total retail sales. The difference between power purchases and sales is line losses. Under the state's RPS, annual renewable energy purchase targets are applicable to retail sales, not total power purchases. As such, stating that 10 percent of load is served by local renewable resources is consistent with the language in the state's RPS.

The impact on annual power costs of increasing the amount of power provided by local renewables to be equal to 10 percent of annual retail sales is shown below in Exhibit 22.

Exhibit 22
Impact on Annual Power Costs of Increasing Local Renewable Purchases to 10% of Retail Sales (nominal)



As shown above, the impact on annual power costs is greatest under Portfolio 1. This is true because, as discussed above, Portfolio 1 a) has the largest differential between utility-scale renewable resource costs and local renewable resource costs (as shown above in Exhibit 18) and b) has the least amount of local renewable purchases in the Plan's base case (as shown above in Exhibit 20).

Excluding the start-up year of 2018, the impact on annual power costs of increasing the amount of load served by local renewables to 10 percent of annual load varies between $1.1 and $5.1 million under Portfolios 1, 2 and 3. The impact on annual power costs is less than $1 million under Portfolio 4. The increases in annual power costs are, on a percentage basis, relatively small as shown in Exhibit 23 below.

Exhibit 23
Impact on Annual Power Cost of Increasing Local Renewable Resources to 10% of Load

Portfolio	Increase in Annual Power Costs (nominal)	Percent Increase in Annual Power Costs
Portfolio 1: Match PG&E	$3.5 to $5.1 million	1.1 to 2.7%
Portfolio 2: PG&E + 10%	$2.0 to $3.9 million	0.6 to 2.0%
Portfolio 3: PG&E + 20%	$1.1 to $2.7 million	0.4 to 1.3%
Portfolio 4: 100% Renewables	$690,000 to $990,000	0.2 to 0.4%

SJCE Cost of Service

This section of the Plan describes the financial pro forma analysis and cost of service for SJCE. It includes estimates of staffing and administrative costs, consultant costs, power supply costs, uncollectable charges, and PG&E charges. In addition, it provides an estimate of start-up working capital and longer-term financial needs.

Cost of Service for SJCE Base Case Operations

The first category of the pro forma analysis is the cost of service for SJCE operations. To estimate the overall costs associated with SJCE operations, the following components have been included:

- Power Supply Costs
- Non-Power Supply Costs
    - Staffing
    - Administrative costs
    - Consulting support
    - PG&E billing and metering charges
    - Uncollectible costs
    - Reserves
    - New programs funding
    - Financing costs
- Pass-Through Charges from PG&E
    - Transmission and distribution charges
    - Power Charge Indifference Adjustment (PCIA) charge
    - Franchise Fee Surcharge

Once the costs of SJCE operations have been determined, the total costs can be compared to PG&E's projected rates. A summary of the various costs detailed below is included in Appendix B – Pro Forma Analysis.

Power Supply Costs

A key element of the cost of service analysis is the assumption that electricity will be procured under a power purchase arrangement (PPA) for both renewable and non-renewable power until local SJCE resources can be developed. Power supply must be obtained by SJCE's procurement consultant prior to commencing operations. The products required from the third-party procurement are energy, capacity (System, Local and Flexible RA products), renewable energy, GHG-free energy, load forecasting, and scheduling coordination.

The calculated 20 year levelized cost of electric power supply, including the cost of the scheduling coordinator and all regulatory power requirements, is between $61 and $72 per MWh as described in the Power Supply section, Exhibit 17. This price represents the price needed to meet the load requirements of the CCA customers. The variation in price is a function of the desired level of renewable resources.

Four power supply scenarios are modeled for this Plan as described in the previous section. The four scenarios are:

- Power supply meeting PG&E current RPS plan
- Power supply meeting 10% more renewable than PG&E
- Power supply meeting 20% more renewable than PG&E
- Power supply meeting 100% renewable resources

To further local economic development goals, the Plan assumes that each of the scenarios will meet 10 percent of the renewable power supply with local renewables. In order to align with SJCE goals, the Plan assumes that "local renewable" power is primarily composed of smaller scale solar projects constructed in SJCE's service territory. On a $/watt basis, the cost of small-scale solar projects is approximately $19 per MWh greater than the cost of larger, utility-scale solar projects as is shown in Exhibit 18.

Non-Power Supply Costs

While power supply costs make up the majority of costs associated with operating SJCE (roughly 60 percent depending on the portfolio scenario), there are several additional cost components that must be considered in the pro forma financial analysis. These additional non-power supply costs are noted below.

Estimated Staffing Costs

Staffing is a key component of the operating the CCA. This feasibility study assumes the City will proceed with the single City operating model. All staffing, consultant, and infrastructure assumptions are detailed in Appendix C. SJCE will have discretion to distribute operational and administrative tasks between internal staff and external consultants in any combination. For this Plan, two scenarios are explored that are considered to be at the maximum and minimum of this spectrum. The first option involves hiring internal staff incrementally to match workloads involved in forming SJCE, managing contracts, and initiating customer outreach/marketing during the pre-operations period (Full Staff Scenario). In the alternative approach, the CCA would hire just three staff internally and contract out the remaining work to consultants (Minimum Staff Scenario). Throughout the rest of this Plan, it is assumed that SJCE will opt for the Full Staff Scenario, but both options are discussed. The full Staff Scenario is selected because it requires the most effort for the City and it provides the most detail about the potential internal operating costs.

Full Staff Scenario

Exhibit 24 provides the estimated staffing budgets for a full staff CCA scenario for the start-up period (Pre-launch in 2017 through full operating in 2018). Staffing budgets include direct salaries and benefits. Prior to SJCE's launch in 2018, it is assumed an operating team will be employed per the example of other CCAs in California thus far to implement the launch of the CCA program. This operating team includes one Executive Director, Director of marketing and public affairs, and account management staffing. The remaining functions will initially be outsourced either in-house or performed by consultants.

Exhibit 24
Staffing Plan (SJCE)

Number of Staff	2017* Pre-Launch	2018 Launch Phases 1-3	2019 Fully Operational
Executive Director	1	1	1
General Counsel & Director of Government Affairs	0	1	1
Director of Power Resources	0	1	1
Regulatory/Legislative Analyst	0	0	1
Administrative Assistant	0	1	1
Director of Administration and Finance	0	0	1
Finance Manager	0	1	1
Director of Marketing and Public Affairs	1	1	1
Power Supply Compliance Specialist	0	1	1
Power Resource Planning and Program Analyst	0	1	2
Community Outreach Manager	0	1	1
Account Service Manager	1	1	1
Account Representatives	1	1	1
Communication Specialists	1	1	2
Executive Assistant	0	1	1
Administrative Analysts	0	1	2
Total Number of Employees	**5**	**14****	**19**
Total Staffing Costs	**$496,250**	**$2,001,267****	**$3,837,839**

*Represents only partial year.
**The number of staff reported for the year 2018 describes the maximum number of staff employed during that year. Because there are three launch phases in that year, each phase has a different number of staff. This plan assumes six staff are employed for Phase 1 (January through May), thirteen for Phase 2 (June through October), and fourteen for Phase 3 (November and December).

Based on this staffing plan, SJCE will initially employ 6 staff members. Once SJCE enters Phase 2, it is anticipated that staffing will increase to approximately 14 employees. The management positions to be hired by SJCE over the first two years are described below:

Executive Director

The Executive Director will be responsible for all aspects of launching and operating a highly-visible start-up organization and building it into an innovative enterprise that benefits SJCE residents and businesses. The Executive Director will direct all activities of the SJCE including operations, resource procurement and planning, energy infrastructure development, finance, legal and regulatory affairs, external communications and strategic planning. The Executive Director will report to the City Manager and will work with numerous stakeholders including County residents, businesses, labor representatives, government officials, and experts in the fields of energy and utility services. The Executive Director will utilize a combination of internal staff and contractors to achieve SJCE's objectives.

Director of Power Supply

The Director of Power Supply will oversee the day-to-day power supply operation of SJCE. In particular, this staff position will work closely with outside consultants, and oversee hedging and power procurement, resource portfolio strategy and other resource planning and compliance analysis. Behind-the-meter SJCE programs will also be coordinated through this position.

General Counsel & Director of Government Affairs

The General Counsel & Director of Government Affairs will oversee the contractual, legal and regulatory compliance and advocacy functions of SJCE. This position will work closely with the CPUC and State/Federal legislators. SJCE will require ongoing regulatory representation to file resource plans, resource adequacy compliance, compliance with California RPS, and overall representation on issues that will impact SJCE and its customers. SJCE should plan on maintaining an active role at the CPUC, CEC, CAISO and the California legislature.

Director of Administration and Finance

The Director of Administration and Finance oversees SJCE's budgets and accounting functions. In addition, this person will develop annual budgets, rates, and credit policies for approval by the governing body. Managing the overall financial aspects of SJCE is expected to be a significant work activity.

Director of Marketing and Public Affairs

The Director of Marketing and Public Affairs is responsible for the enrollment and notification of new customers. In addition, this staff person will market SJCE, and provide ongoing communication with SJCE's communities and customers. A significant amount of customer service and key account representation will be necessary in addition to regular marketing services. This position will be the point person for the outsourced data management and customer service consultants.

Future Staff

As additional customers join SJCE, duties can be shifted from third-party consultants to in-house staff if internal staffing is desired and/or more cost effective.

Minimum Staff Scenario

To build the minimum staff possible to run SJCE, all tasks described above would be completed by consultants on a contract basis. It is assumed that these contracts would be managed by the Executive Director and two in-house staff, such as the Regulatory and Finance managers, with a total estimated all-in staffing cost of approximately $900,000 per year. In addition, additional consultants would have to be hired to manage the tasks not managed by full-time staff. It is anticipated that the cost difference between all-in staff cost and consultant cost is minimal. The projected savings difference under each option are therefore not anticipated to be significant.

Administrative Costs

Infrastructure or overhead needed to support the organization includes computers and other equipment, office furnishings, office space, utilities and miscellaneous expenses. Exhibit 25 shows that these expenses are estimated at $200,000 during program pre-startup for the full staffing scenario. Office space and utilities are ongoing monthly expenses that will begin to accrue before revenues from program operations commence and are therefore assumed to be financed. If existing City office space is available at a lesser price[41], rates will be lower and CCA-related savings higher.

It is estimated that the per employee start-up cost is approximately $10,000. This expense covers computer and furniture needs. An additional annual expense of $180,000 for office space, and approximately $120,000 per year in office supplies and utilities costs is expected. Miscellaneous start-up costs of $500,000 are estimated for 2017 through 2018 to address the general cost of mailing notifications, meetings, communication and other start-up activities. In addition, it is assumed that computers will need to be replaced every 5 years. Finally, additional miscellaneous expense budgets are estimated for general start-up costs in 2017 and 2018.

[41] If the CCA function is housed in City Hall, then it will need to pay its prorate share of debt service for City Hall bonds

Exhibit 25 Estimated Infrastructure Cost by Year (SJCE – Full-Staff Scenario)			
	2017	**2018**	**2019**
Infrastructure Costs			
Computers	$25,000	$45,000	$25,500
Furnishings	$25,000	$45,000	$25,500
Office Space	$30,000	$180,000	$183,600
Utilities/Other Office Supplies	$20,000	$120,000	$122,400
Miscellaneous Expenses	$100,000	$400,000	$0
Total Infrastructure Costs	**$200,000**	**$790,000**	**$357,000**

While the minimal staffing option would save some infrastructure costs to the City, it is anticipated that the consultant staff would include similar cost. It is therefore not anticipated that the minimal staff option would not result in any significant cost differences.

Outside Consultant Costs

Consultant costs include outside assistance for legal and regulatory work, communication and marketing, data management, financial consulting, technical consulting and implementation support. CCA data management providers provide customer management system software, and oversee customer enrollment, customer service, as well as the payment processing, accounts receivable and verification services. In addition, estimated funding for other consulting support and/or city funding (such as HR, legal, customer service, etc.) is provided. Exhibit 26 shows the estimated consultant costs during the first three years. Assumptions about consultant fees are provided on a monthly and annual basis in Appendix C.

Exhibit 26 Estimated Consultant Costs by Year (SJCE)			
	2017	**2018**	**2019**
Legal/Regulatory*	$270,000	$360,000	$360,000
Communication	$50,000	$300,000	$120,000
Data Management	$0	$2,592,169	$4,504,761
Financial Consulting**	$300,000	$600,000	$640,000
Technical Consultant	$60,000	$120,000	$120,000
Other Consulting/City Functions	$300,000	$550,000	$300,000
Total Consultant Costs	**$920,000**	**$4,402,169**	**$5,924,761**

*Legal/regulatory consulting refers only to legal counsel regarding CPUC compliance, filings, etc.
**Financial consulting includes legal fees for counsel on CCA financing.

The estimate for each of the services is based on costs experienced by other CCAs and specific SJCE circumstances. Consultant costs are increased by inflation every year. It should be noted that these costs are estimated for the Full Staff Scenario. Under the Minimal Staff Scenario, consultant costs are increased such that total CCA operational costs remain the same under each staffing scenario.

PG&E Billing & Metering Costs

PG&E provides billing and metering services to SJCE based on published tariffs. The estimated costs payable to PG&E for services related to SJCE start-up include costs associated with initiating service with PG&E, processing of customer opt-out notices, customer enrollment, post enrollment opt-out processing, and billing fees.

Customers who establish service with SJCE will be automatically enrolled in the program and have 60 days from the date of enrollment to customer opt-out of the program. Such customers will be provided with two opt-out notices within this 60-day post enrollment period. The first notice will be mailed to customers approximately 60 days prior to the date of automatic enrollment. A second notice will be sent approximately 30 days later. Following automatic enrollment, two additional opt-out notices will be provided within the 60-day period following customer enrollment. It is estimated that the billing charges will be approximately $1.2 million for 2018 and $2.2 million for 2019, as shown in Exhibit 27.

Exhibit 27
Utility Transaction Fees (SJCE)

	2017	2018	2019
Total PG&E Transaction Fees	$0	$1,243,547	$2,193,871

Uncollectible Costs

As part of the operating costs, the SJCE must account for customers that do not pay their electric bill. While PG&E will attempt to collect funds, approximately 0.5 percent of revenues are estimated as uncollectible[42]. This cost is therefore added to the SJCE revenue requirement.

Financial Reserves

SJCE is assumed to receive capital financing during its start-up through phase 3. After a successful launch, SJCE must build up a reserve fund that is available to address contingencies, cost uncertainties, rate stabilization or other risk management factors faced by SJCE. Therefore, this Plan assumes that SJCE will begin building its reserve starting from its launch. After three full operating years, it is estimated that the assumed rate will have accumulated enough reserve for 3 months of expenses. This level of reserves is based on industry standards for electric utilities and will provide financial stability and assist SJCE in obtaining favorable rates if additional financing is needed. After that point, revenues that exceed costs can begin to finance a rate stabilization fund, new local renewable resources, additional economic development projects or lower rates. These financial reserves are documented in Appendix B.

[42] Based on historic IOU uncollectible revenue as percent of total revenue.

New Programs/Projects Costs

Once the reserve fund has reached its target, the revenue requirement includes budget for new customer programs including local renewable resources projects, distributed generation support, additional energy efficiency program offering, etc. Rate design programs, such as Net Energy Metering and Economic Development rates, can be implemented sooner as these do not require large capital investments. These potential offerings are discussed later in the Plan.

Financing Costs

In order to estimate financing costs, a detailed analysis of working capital needs as well as start-up capital is estimated. Each component is discussed below.

Cash Flow Analysis and Working Capital

This cash flow analysis estimates the level of working capital that will be required until full operation of SJCE is achieved. For the purposes of this Plan, it is assumed that SJCE pre-operations begin in July 2017 and continue through December 2017. In general, the components of the cash flow analysis can be summarized into two distinct categories: (1) Cost of SJCE operations, and (2) Revenues from SJCE operations. The cash flow analysis identifies and provides monthly estimates for each of these two categories. A key aspect of the cash flow analysis is to focus primarily on the monthly costs and revenues associated with SJCE and specifically account for the transition or "phase-in" of SJCE customers. The cash flow analysis assumes the phase-in schedule for SJCE (see page 18).

The cash flow analysis also provides estimates for revenues generated from SJCE operations or from electricity sales to customers. In determining the level of revenues, the cash flow analysis assumes the customer phase-in schedule noted above, and assumes that SJCE provides a discount of the existing PG&E rates for each customer class.

The results of the cash flow analysis provide an estimate of the level of working capital required for SJCE to move through the pre-operations period. This estimated level of working capital is determined by examining the monthly cumulative net cash flows (revenues minus cost of operations) based on assumptions for payment of costs by SJCE, along with an assumption for when customer payments will be received. The cash flow analysis assumes that customers will make payments within 60 days of the service month, and that SJCE will make payments to suppliers within 30 days of the service month. This analysis is somewhat conservative because customer payments begin to come in soon after the bill is issued, and most are received before the due date. At the same time, some customer payments are received well after the due date. The 30-day net lag is a conservative assumption for cash flow purposes.

For purposes of determining working capital requirements related to power purchases, SJCE will be responsible for providing the working capital needed to support electricity procurement unless the electricity provider can provide the working capital as part of the contract services. In addition, SJCE will be obligated to meet working capital requirements related to program management. While SJCE may be able to utilize a line of credit, for this Plan, it is assumed that this working capital requirement is included in the financing associated with start-up funding.

A summary of working capital needs is presented below on Exhibit 28.

Exhibit 28 Working Capital Needs (SJCE)		
	2017 Pre-launch	**2018 Launch Phases 1-3**
Bonding & Security Requirement (CPUC)	$0.1 million	-
PG&E Program Reserve	$0.4 million	-
Start-up Costs	$1.6 million	$7.9 million
Working Capital (Cash Flow)	$3.4 million	$42.1 million
Total Capital Needed	**$5.5 million**	**$50.0 million**

For comparison, Marin Clean Energy (MCE) started with $3.3 million in pre-launch funding[43] and is now operating with $21.7 million in working capital[44]. MCE serves electrical load roughly equivalent to 46 percent of SJCE's estimated load[45]. Similarly, Sonoma Clean Power (SCP) acquired $6.2 million in pre-launch capital[46], and now maintains working capital reserves of $25 million[47] while serving 56 percent of SJCE's estimated load[48]. Therefore, the working capital needs assumed in the Business Plan are in line with the experience of successfully operating CCAs on a $/GWh basis.

Total Financing Requirements

The start-up of SJCE will require a significant amount of start-up capital for three major functions: (1) staffing and consultant costs; (2) infrastructure costs (office space, computers, etc.) and (3) CPUC Bond and PG&E security deposits.

Staffing, consultant and other program initiation costs have been discussed previously. In addition, the Public Utilities Code requires demonstration of insurance or posting of a bond sufficient to cover reentry fees imposed on customers that are involuntarily returned to PG&E

[43] https://www.mcecleanenergy.org/wp-content/uploads/2016/01/MCE-Start-Up-Timeline-and-Initial-Funding-Sources-10-6-14-1.pdf
[44] https://www.mcecleanenergy.org/wp-content/uploads/2016/09/MCE-Audited-Financial-Statements-2015-2016.pdf
[45] https://www.mcecleanenergy.org/wp-content/uploads/2016/01/Marin-Clean-Energy-2015-Integrated-Resource-Plan_FINAL-BOARD-APPROVED.pdf
[46] https://sonomacleanpower.org/wp-content/uploads/2015/01/2014-SCPA-Audited-Financials.pdf
[47] https://sonomacleanpower.org/wp-content/uploads/2015/01/2016-05-SCP-Compiled-Financial-Statements.pdf
[48] https://sonomacleanpower.org/wp-content/uploads/2015/01/2015-SCP-Implementation-Plan.pdf

service under certain circumstances. PG&E also requires a bond equivalent to two months of transaction fees.

For SJCE, the total financing requirement, including working capital, during the pre-launch to full operations, are estimated to be approximately $5.5 million, increasing to approximately $50 million following full enrollment.

Current CCA Funding Landscape

The CCA market is rapidly expanding with increasingly proven success. To date, there are five operational CCAs in California that have demonstrated the ability to generate positive operating results. The early financial adopters were community banks in the CCA service territory, but now a mix of regional and large national banks have shown increased levels of interest. This expanded interest should give the City comfort that it will have access to an adequate number of potential financial counterparties.

As CCAs have successfully launched across the State and a more robust data set of opt-out history becomes available, the financial community has been more comfortable in providing credit support to CCAs. All programs that have launched to date and those in development have relied on a sponsoring municipality to provide support for obtaining needed funds. This support has come in varied forms which are summarized in Exhibit 29.

Exhibit 29
Forms of Support

CCA Name	Pre-Launch Funding Requirement[1]	Funding Sources
Marin Clean Energy	$2- $5 million	Startup loan from the County of Marin, individual investors, and local community bank loan.
Sonoma Clean Power	$4 - $6 million	Loan from Sonoma County Water Authority as well as loans from a local community bank secured by a Sonoma County General Fund guarantee.
CleanPowerSF	~$5 million	Appropriations from the Hetch Hetchy reserve (SFPUC).
Lancaster Choice Energy	~$2 million	Loan from the City of Lancaster General Fund.
Peninsula Clean Energy	$10 - $12 million	PCE has also obtained a $12 million loan with Barclay and almost $9 million with the County of San Mateo for start-up costs and collateral.
Silicon Valley Clean Energy[2]	$2.7 million	Loans from County of Santa Clara and City members $21 million Line of Credit with $2 million guarantee, otherwise no collateral,

[1] Source: Respective entity websites and publicly available information. These funds do not include all funds needed or cover a consistent period.
[2]Silicon Valley Clean Energy is not yet an operating CCA, but they expect to launch service in April of 2017.[49]

[49] https://www.svcleanenergy.org/

A review of the current state of options for obtaining funds for these initial phases is detailed below:

Direct Loan from City of San José –The City could loan funds from the General Fund for a loan to fund all or a portion of the pre-launch through Phase 3 needs. The City would be secured by the CCA revenues once launched. The City would likely assess a risk-appropriate rate for such a loan which is likely higher than the City earns for funds otherwise invested. This rate is estimated to be 4.0 percent to 6.0 percent per annum.

Collateral Arrangement from City of San José – As an alternative to a direct loan from the City, the City could establish an escrow account to backstop a lender's exposure to the CCA. The City would agree to deposit funds in an interest-bearing escrow account which the lender could tap should the CCA revenues be insufficient to pay the lender directly.

Loan from a Financial Institution without Support – Silicon Valley Clean Energy Authority (SVCEA) was able to use this option to fund ongoing working capital. After members funded a total of $2.7 million in start-up funds, SVCEA has obtained a $20 million line of credit without collateral.

Vendor Funding – The City can pursue arrangements with its power suppliers to eliminate or reduce the need for or size of funding for the start-up and operations. This could come in a number of forms such as a "lockbox" approach with a power provider. However, this approach is less transparent and the associated cost may outweigh the benefit of eliminating or reducing the need for a bank facility.

Revenue Bond Financing – This is not a feasible option at this point given the start-up nature of the enterprise and due to restrictions in the San José City Charter.

CCA Financing Plan

While there are many options available to SJCE for financing, the initial start-up funding is assumed to be provided via short-term financing. SJCE will recover the principal and interest costs associated with the start-up funding via subsequent retail rates. It is anticipated that the start-up costs will be fully recovered within the first five years of SJCE operations.

The anticipated start-up and working capital requirements for SJCE through Phase 1 are approximately $5 million. Once the SJCE program is operational, these costs would be recovered through retail rates. Actual recovery of these costs will be dependent on third-party electricity purchase prices and decisions regarding initial rates for Phase 1 customers.

Additional financing will be needed at the beginning of Phase 2. Depending on market conditions and payment terms established with the third-party suppliers, the loan may need to be increased to approximately $50 million for the start of Phase 2. This number will be refined as the SJCE program becomes operational and bids are received from power providers.

Based on recent information regarding financing options for CCA's, the Plan's financial analysis assumes that SJCE can obtain a loan for the first $5 million with a term of 5 years at a rate of 5.5 percent. The second loan for $50 million is assumed for a 20-year term at 5.5 percent. While the City may arrange for vendor funding for the additional financing needs, the cost will still need to be accounted for. In the case of vendor funding, the City will not have to take out a loan, but will pay for the cost of the financing through vendor fees.

The detail of the base case cash flow analysis is provided in Appendix B.

Products, Services, Rates Comparison and Environmental/Economic Impacts

This section of the Plan provides a comparison of service and rates between PG&E and SJCE. Rates are evaluated based on total SJCE electric total bundled rates as compared to PG&E's total bundled rates. Total bundled electric rates include the rates charged by SJCE, including non-bypassable charges, plus PG&E's delivery charges. This section of the Plan also includes the environmental impacts based on the reduction in GHG, and the economic development impact on local jobs and overall economic activity created by SJCE programs.

Rates Paid by PG&E Bundled Customers

The average customer weighted PG&E rates have been calculated based on current rate schedules and SJCE's projected customer mix. PG&E's current rates and surcharges have been applied to customer load data aggregated by major rate schedules to form the basis for the PG&E rate forecast.

The average PG&E delivery rate, which is paid by both PG&E bundled customers and SJCE customers, has been calculated based on the forecasted customer mix for SJCE. For future years, the PG&E rate forecast assumes the delivery costs will increase by 2 percent per year, a conservative assumption given the history of PG&E non-power supply rate increases.

Similarly, the current average power supply rate component for PG&E bundled customers has been calculated based on the estimated SJCE customer mix. Finally, the PG&E power supply rates have been projected to increase based on the renewable and non-renewable market price forecast, regulatory requirement for RPS, storage requirement, and resource adequacy objectives. This results in an average annual growth rate of 2.8 percent over the 10-year analysis period, again a conservative assumption. This resultant PG&E bundled rate is consistent with similar forecasts provided in other CCA-feasibility studies.

Rates Paid by SJCE Customers

It is anticipated that SJCE's rate designs will initially mirror the structure of PG&E's rates so that similar rates can be provided to SJCE's customers and bill comparisons can be made on an apples-to-apples basis. PG&E are moving towards Time-of-Use rates for all customers and it is assumed SJCE will follow this transition initially. In determining the level of SJCE rates, the financial analysis assumes the customer phase-in schedule noted above and that the implementation phase costs are financed via start-up loans (per "CCA Financing Plan" section).

In addition to paying SJCE's power supply rate, SJCE customers will pay the PG&E delivery rate and non-bypassable charges. The calculation of the delivery rate is described earlier (see "Rates paid by PG&E Bundled customers" section). The non-bypassable charges that are payable to PG&E by SJCE customers include:

- Power Charge Indifference Adjustment (PCIA)
- Franchise Fee Surcharge

Power Charge Indifference Adjustment

The PCIA is a charge that is designed to keep bundled customers indifferent when other customers leave bundled service and cover any of the IOU's (in this case PG&E) stranded costs associated with unavoidable generation related costs purchased on behalf of the departing CCA customers. The PCIA is calculated annually by subtracting the market price of wholesale power from the incumbent utility's average cost of power supply in place at the time the CCA customer leaves PG&E based on a methodology determined by the CPUC.[50] The CPUC oversees the calculation and methodology every year as part of the annual ERRA process. As a CCA, SJCE can participate in this process and provide input and objections as needed.

For this Plan, it was assumed in the base case that the PCIA increases by 10 percent over the 2017 level for 2018. Post-2018, the PCIA is expected to grow based on the inverse of the difference in the growth between PG&E's generation cost and market prices. The PCIA is calculated based on the difference between PG&E's surplus resource cost and the market price. Therefore, as market prices increase more than the cost of surplus resource, PG&E's PCIA rate decreases as their surplus resources become more cost effective relative to market prices. This methodology results in a base case PCIA forecast that decreases by an average of 1.1 percent per year over the 10-year period. This resultant PCIA forecast is consistent with PCIA rate forecasts contained in other CCA feasibility studies.

Franchise Fee Surcharge

The franchise fee is a surcharge that PG&E pays cities and counties for the right to use public streets to provide utility services. The franchise fee is a revenue source for municipalities imposed on privately owned utilities. The franchise fee is a "rental" or "toll" for the use of a municipality's streets and poles, as well as for permission to provide service in their jurisdiction. "The Franchise Act establishes that a franchise fee of 2 percent of the franchisees gross annual receipts arising from the use, operation, or possession of the franchise …. within the city limits[51]" must be paid to the municipality.

PG&E collects the surcharges and passes them to cities and counties. This tax is part of PG&E's current rates and is therefore passed on to the CCA customers as a non-bypassable charge called the Franchise Fee Surcharge. PG&E will continue to collect the Franchise Fee Surcharge for both

[50] See D.-6-07-030 as modified by D. 11-12-018.

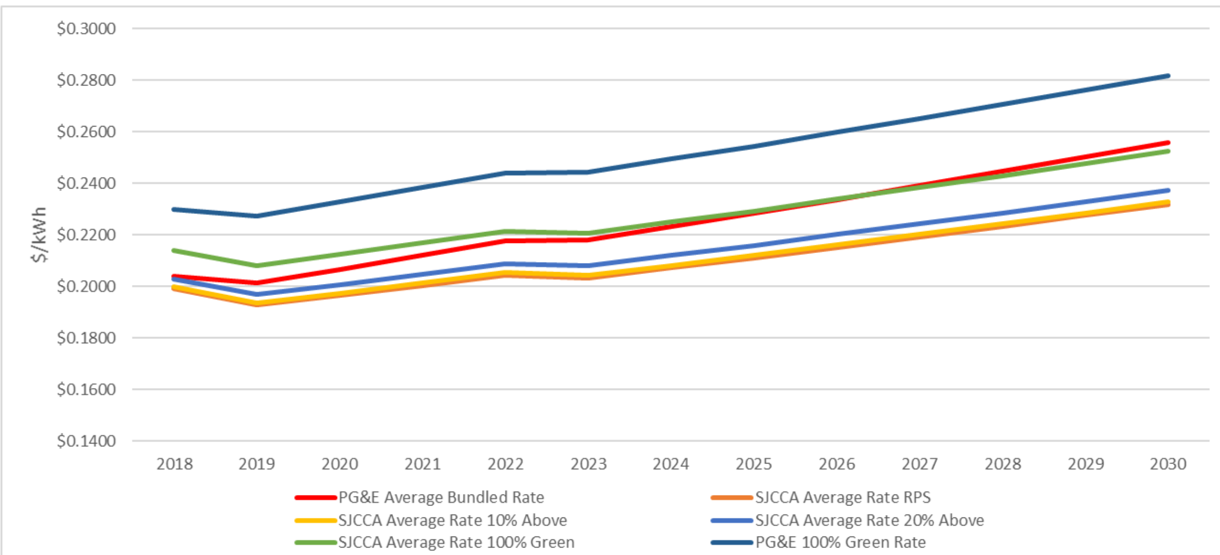
[51] The California Municipal Law Handbook. 2002 Edition

generation and distribution services and pay the owed revenue to the cities and counties, regardless of the power supplier. The franchise fee is not forecast to change during the analysis horizon. The formation of a CCA does not affect the amount of franchise fee paid to cities and counties, and also does not require the negotiation of a new franchise fee agreement.

Rate Impacts

Based on SJCE's projected power supply costs, PCIA and operating costs, and PG&E's power supply and delivery costs, forecasts of SJCE and PG&E total rates have been developed. These rates are illustrated below on Exhibit 30.

Exhibit 30
Average Total Retail Rate Comparison



The SJCE RPS residential rate with an equal amount of renewable power to that projected for PG&E is approximately 4.2 percent lower initially then ranges from 4.9 to 9.4 percent lower, as can be seen in Exhibit 30. The SJCE residential rate with 10 percent more renewable power is 3.8 percent lower initially then ranges from 4.5 to 8.9 percent lower, while the rate with 20 percent more renewable is 2.2 percent lower initially then ranges from 2.7 to 7.2 percent lower. The SJCE residential rate with 100 percent green power is 3.4 percent higher than PG&E's projected bundled rate initially then ranges from 2.7 percent higher to 1.3 percent lower. PG&E's average bundled rate with the residential 2017 cost of 2.61 cents per kWh surcharge for 100% renewable is also shown. The rates calculated under this Plan are for comparison to PG&E rates only. Under formal operations, the SJCE policymakers will determine the actual rates to be offered to its customers.

Based on these estimated SJCE discounts off the comparable PG&E rate, Exhibit 31 provides a comparison of the indicative bundled rates for SJCE's products based on the projected 2017 PG&E rate. These indicative rates are calculated as a percentage off PG&E's bundled rates.

Exhibit 31 Indicative Rate Comparison in $/kWh					
Rate Class	**2017 PG&E Bundled Rate***	**Indicative SJCE RPS Bundled Rate**	**Indicative SJCE 10% more Renewable Bundled Rate**	**Indicative SJCE 20% more Renewable Bundled Rate**	**Indicative SJCE 100% Renewable Bundled Rate**
Residential	0.19971	0.1913	0.1921	0.1953	0.2063
Small Commercial	0.22515	0.2157	0.2166	0.2202	0.2326
Medium Commercial	0.20053	0.1921	0.1929	0.1961	0.2071
Large Commercial	0.17618	0.1688	0.1695	0.1723	0.1820
Street Lights	0.21785	0.2087	0.2096	0.2131	0.2250
Standby	0.14608	0.1399	0.1405	0.1429	0.1509
Agriculture	0.17606	0.1687	0.1694	0.1722	0.1819
Industrial	0.13985	0.1340	0.1345	0.1368	0.1445
Total	**0.18779**	**0.1799**	**0.1807**	**0.1837**	**0.1940**
Initial Rate Savings in 2019 from PG&E Bundled Rate		**4.2%**	**3.8%**	**2.2%**	**-3.4%**
Rate Savings After Fully Operational		**4.8 – 9.4%**	**4.5 – 8.9%**	**2.7 – 7.2%**	**-2.7 – 1.3%**

*PG&E bundled average rate based on PG&E's 2017 Rates.

A financial pro forma in support of these rates can be found in Appendix B.

Exhibit 31 provides the rate comparison of SJCE projected rates to PG&E's estimated bundled rate provided in the 2017 ERRA filing. Exhibit 32 provides the comparison for a residential customer of SJCE projected rates to PG&E's bundled rate and PG&E's rate offerings for additional renewable power. For 2017, PG&E charges $0.0261 per kwh for each additional renewable kwh requested by a residential customer.

Exhibit 32 Residential Rate Comparison for 2019			
	PG&E Indicative Rate	**SJCE Indicative Rate**	**Percent Difference**
RPS Scenario	0.1997	0.1913	4.2%
RPS + 20% (50% Renewable)	0.2128	0.1953	8.2%
100% Renewable	0.2232	0.2063	7.6%

Exhibit 32 shows that SJCE's portfolios with additional renewable resources can provide significant savings to residential customers compared to PG&E's additional renewable rate plans.

Impact of Resource Plan on Greenhouse Gas (GHG) Emissions

The amount of renewable power in PG&E's power supply portfolio is 30 percent[52] and will rise to 37 percent by 2020 and 50 percent by 2030[53]. At this time, PG&E's resource mix is 59 percent GHG-free due to power supply from large hydro, nuclear, and renewable resources. Most likely, PG&E will reduce market purchases (i.e., natural gas fired generation) as SJCE customers are leaving PG&E service.

SJCE is committed to reductions in GHG emissions. As part of that commitment, SJCE plans to purchase GHG-free resources (such as renewable resources) to meet the current PG&E GHG-free portfolio. In addition, the 10 percent more and 20 percent more renewable resources than PG&E scenarios will increase the amount of GHG-free resources by 10 percent or 20 percent of load. For this plan, only the additional RPS purchases are counted in the GHG emissions savings resulting from the implementation of the CCA program. In addition, because it is unclear what specific resources is being replaced by renewable power, an estimated range of avoided emissions is provided. The range is based on estimates from CARB that range from 400 tons per GWH to 707 tons per GWH.

Based on the power supply strategy described previously (see "Power Supply Strategy & Cost" section), GHG emission reductions due to additional renewable resource procurement resulting from the formation of SJCE are estimated to range from 152,000 to 264,000 metric tons carbon dioxide equivalent (MT CO_2e) per year in 2019 assuming SJCE's share of power from renewable energy is 10 percent greater than PG&E and SJCE plans to meet PG&E's GHG free resource mix. This represents a 10 percent to 18 percent reduction in San José's GHG emissions from electricity generation[54], equivalent to removing up to 56,000 passenger vehicles from the road or the energy usage from nearly 28,000 homes each year.[55] In the scenario wherein SJCE achieves 20 percent higher RPS than PG&E, the estimated range of GHG emission savings is 304,000 to 528,000 MT CO_2e per year in 2019, representing 21 percent to 36 percent of San José GHG emissions from electricity generation. This reduction equates to removing up to 112,000 passenger vehicles from the road or the energy usage from nearly 56,000 homes each year. The baseline for comparison is the projected resource mix used by PG&E in the same time period. Exhibit 33 details these reductions.

---

[52]https://www.pge.com/pge_global/common/pdfs/your-account/your-bill/understand-your-bill/bill-inserts/2016/11.16_PowerContent.pdf

[53] http://www.cpuc.ca.gov/RPS_Procurement_Rules_33/, http://www.energy.ca.gov/portfolio/16-RPS-01/

[54] https://www.sanjoseca.gov/DocumentCenter/View/55505

[55] https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

Exhibit 33 Comparison of GHG Reduction by SJCE		
	10% Additional Renewable/ 10% Additional GHG-Free	20% Additional Renewable/ 20% Additional GHG-Free
2019 Load (GWH)	3,769	3,769
SJCE Additional Renewable (GWH)	377	754
CO2 reduction – Low (Metric Tons of CO_2e)	152,267	304,535
CO2 reduction – High (Metric tons of CO_2e)	263,830	527,660

Local Resources/Behind the Meter SJCE Programs

SJCE will have the option to invest in a range of programs to expand renewable energy use and enhance economic development in the San José metropolitan area. Increased renewable energy use can be accomplished by supporting customers wishing to own small renewable generation (net energy metering), purchasing from small local for-profit renewable generators (feed-in tariffs), purchasing renewable resources directly, or supporting electric vehicle use. Each of these programs also yields economic development benefits by spending locally and saving local customers money. In addition, economic development can be accomplished through additional support for low-income customers or extra support for new or growing businesses. The following sections discuss these programs.

Economic Development

There are several programs that CCAs can offer to stimulate additional local economic development in their service area. One is a special economic development rate to encourage manufacturers to site in San José thus supporting San José's strategy to stimulate manufacturing jobs.

Another type of program that promotes economic development is to provide incentives for businesses to locate in the service area, remain there, or expand. In order for economic incentives to be provided, the utility must show that the addition of the new customers will benefit (or not harm) the existing rate payers. PG&E offers a wide range of rebates to businesses across different sectors, including agricultural, computing and data services, food services and refrigeration, HVAC, and lighting[56]. SJCE could offer similar rebate programs better targeted to the business sectors of interest to their service area. If, for example, a large industrial customer would like to locate within PG&E/SJCE service area, increased efficiency may result in decreased costs to all other customers, thus an incentive could be paid to the new industrial customer.

[56]https://www.pge.com/en_US/business/save-energy-money/business-solutions-and-rebates/product-rebates/product-rebates.page

Net Energy Metering (NEM)

SJCE could establish a Net Energy Metering (NEM) program for qualified customers in their service territory to encourage wider use of distributed energy resources (DER) such as rooftop solar. NEM programs allows energy customers who generate some or all of their own power to sell excess generation to the grid and benefit from a credit for those sales when they become a NEM consumer.

PG&E currently offers a NEM program in which customers receive an annual "true-up" statement at the end of every 12-month billing cycle. This allows customers to balance credit earned in summer months with charges accrued in the winter. Customers earn power credits at the market rate at the time of generation, between $0.03 and $0.04 per kilowatt-hour (kWh)[57], though they are not paid for excess generation. Credits unused at the end of each year expire. This policy therefore incentivizes customers to limit the size of their generation system given as excess generation will not provide a return.

All of the CCAs currently operating in California also offer NEM programs and all three of the most recently operational CCAs have offered them at the launch of service[58]. These programs are across the board more favorable for NEM customers than the IOU's. On generation rates, both Marin Clean Energy (MCE) and Sonoma Clean Power (SCP) offer $0.01/kWh more than PG&E. Meanwhile, Lancaster Choice Energy (LCE) offers double the rate per kWh that Southern California Edison offers. The more important difference, however, is that these CCAs allow for roll-over of earned credits as well as cashing out on credits earned over $100. Finally, MCE bills NEM customers on a monthly basis to save customers from incurring a full year's worth of expenses all at once.

All of these CCA-managed NEM programs offer greater incentives for customers in their service area to invest in more and larger DER. This has the benefit of increasing the supply of renewable resources available to these CCAs as well as encouraging high participation rates among current and potential NEM customers. SJCE has the option to implement a similar NEM program.

---

[57]https://www.pge.com/en_US/residential/solar-and-vehicles/green-energy-incentives/solar-and-renewable-metering-and-billing/how-to-read-your-bill/how-to-read-your-bill.page
[58]http://www.leanenergyus.org/wp-content/uploads/2013/10/CleanPowerSF-Implementation-Plan-March-2010.pdf,http://www.peninsulacleanenergy.com/resources/frequently-asked-questions/#nem-faq, http://www.lancasterchoiceenergy.com/your-options/personal-choice/

Feed-in Tariffs

Feed-in tariffs (FIT) offer terms by which electric service providers such as IOUs and CCAs purchase power from small-scale renewable electricity projects within their service territory. In contrast with NEM programs, which typically target owners of homes and small businesses who wish to install a rooftop photovoltaic (PV) system, FIT programs target owners of larger generation projects, in the range of 0.5-3 MW. These could be larger rooftop photovoltaic (PV) systems located at industrial sites or ground-mounted shade in parking lots.

PG&E currently offers its Renewable Feed-in-Tariff (ReMAT), available to renewable generation projects from 1.5 to 3 MW, with prices ranging from $61 - $89 per Megawatt hour (MWh)[59]. SCP offers its own FIT program for generating facilities under 1 MW at a flat rate of $95/MWh[60]. MCE also offers a FIT program for generating facilitates under 1 MW with prices ranging from $90 - $137.66/MWh[61].

In developing a FIT program of its own, SJCE would incentivize customers in their service area to develop local renewable resources and improve participation among this customer class as well. If the FIT resources are certified, then SJCE may be able to use the FIT program as a long-term RPS procurement strategy.

Local Generation Resources Development

A final option to drive growth in local renewable generation resources within the SJCE service area is for the CCA itself to build or acquire generation resources. MCE currently has 10.5 MW of CCA-owned local solar PV projects under development and is in the process of adding two additional sites with a potential of up to 150 MW total[62]. This model of CCA-owned resources provides CCAs with a guaranteed renewable power source as well as local economic stimulus.

Electric Vehicle (EV) Programs and Charging Stations

Encouraging electric vehicle use can both increase load serving entity (“LSE”) load and simultaneously generate environmental benefits. Many LSEs offer special rates for electric vehicle charging. PG&E offers two non-tiered, time-of-use (TOU) plans: EV-A combines the loads of vehicle charging with the load of the residence. EV-B customers install a separate meter explicitly for vehicle charging[63]. TOU rates encourage vehicle charging at times when energy is

---

[59]https://www.pge.com/en_US/for-our-business-partners/floating-pages/remat-feed-in-tariff/remat-feed-in-tariff.page
[60]http://sonomacleanpower.org/profit/#summary
[61]https://www.mcecleanenergy.org/wp-content/uploads/FIT_Tariff_5.15_FINAL.pdf
[62]https://www.mcecleanenergy.org/wp-content/uploads/2016/01/Marin-Clean-Energy-2015-Integrated-Resource-Plan_FINAL-BOARD-APPROVED.pdf
[63] http://www.pge.com/myhome/environment/whatyoucando/electricdrivevehicles/rateoptions/

cheapest or system load is lowest. MCE offers a similar program for their customers with lower rates[64].

In addition to targeted rate programs, CCAs can encourage electric vehicle use by investing in local electric vehicle charging stations. Silicon Valley Power (SVP), a municipal utility, opened the largest public electric vehicle charging center in the State in April. The facility features 48 Level 2 chargers and one DC Fast Charger[65]. SCP negotiated significant discounts off the manufacturer's suggested retail price in 2016 and is looking to continue this program in 2017.[66] SJCE could invest in similar projects to promote electric vehicle use within its service area.

Low Income Programs

PG&E offer assistance to low-income customers on both one-time and long-term bases. PG&E offers one-time energy credits up to $300 through their Relief for Energy Assistance through Community Help (REACH) program.

For customers in need of more sustained assistance, PG&E offers rates that are 20 percent or lower for qualifying households under the California Alternate Rate Energy (CARE)[67] program. The CARE program is mandatory for IOUs per California Public Utilities Code 739.1. The program is set up for electric corporations that have 100,000 or more customer accounts to provide 30-35 percent discount on electric utility bills on households that are at or below 200 percent of the federal poverty line. Funding for CARE is collected on an equal cents/kWh basis from all customer classes except street lighting. This program, like other PG&E programs, would continue to be available to CCA customers.

In addition, the Family Electric Rate Assistance (FERA) Program can provide a monthly discount on electric bills. This program is designed for income-qualified households of three or more persons. Finally, the California Department of Community Services and Development (CSD) oversees a federal program, Low-income Home Energy Assistance Program (LIHEAP), which offers help for heating or cooling homes and help for weatherproofing homes.

At present, most California CCAs simply match their incumbent IOU's low-income programs, as in the case of MCE and SCP. It is important to note that PG&E is the only IOU in the State of California to charge the PCIA to CARE customers. It is assumed that SJCE will continue to provide the same support to low-income customers as does PG&E.

---

[64] https://www.mcecleanenergy.org/electric-vehicles/
[65] http://www.siliconvalleypower.com/Home/Components/News/News/5036/2065
[66]http://www.sonomawest.com/sonoma_west_times_and_news/news/sonoma-clean-power-enters-world-of-electric-vehicles-with-new/article_3b072a48-b1a7-11e6-810f-0ff384673161.html

[67]https://www.pge.com/en_US/residential/save-energy-money/help-paying-your-bill/payment-assistance-overview/payment-assistance-overview.page

Economic Impacts in the Community

The analyses contained in this Plan of forming SJCE has focused only on the direct effects of this formation. However, in addition to direct effects, indirect microeconomic effects are also expected.

The indirect effects of creating SJCE include the effects of increased commerce, and improved environmental and health conditions. Within this Plan, an IO analysis is undertaken to analyze these indirect effects. The IO model turns on the assumption that forming SJCE will lead to lower energy rates for their customers. Three types of impacts are analyzed in the IO model. These are described below.

Local Investment – SJCE will likely choose to implement programs to incentivize investments in local distributed energy resources (DER). Participants in SJCE may pursue local clean DER. These resources can be behind the meter or community projects where several customers participate in a centrally located project (e.g. “community solar”). This demand for local renewable resources will lead to an increase in the manufacturing and installation of DER and lead to an increase in employment in the related manufacturing and construction sectors.

Increased Disposable Income – Establishing SJCE will lead to reduced customer rates for energy, more disposable income for individuals, and greater revenues for businesses. These cost savings would then lead to more investment by individuals and businesses for personal or business purposes. This increase in spending will then lead to increased employment for multiple sectors such as retail, construction, and manufacturing.

Environmental and Health Impacts – With the creation of SJCE, other non-commerce indirect effects will occur. These may be largely environmental such as improved air quality or improved human health due to SJCE utilizing mainly renewable energy sources versus continuing use of traditional energy sources which may have a greater GHG footprint. This resource strategy significantly reduces GHG emissions compared with PG&E’s current resource mix. While the change in GHG emissions is not modeled directly in economic development models used in this Plan, the reduction of these GHGs may be captured in indirect effects projected by the models.

Input-Output Modeling (IO modeling)

IO modeling is a quantitative analysis representing relationships (dependence) between industries in an economy. IO models are based on the implicit assumption that each basic sector has a multiplier, or ripple effect, on the wider economy because each sector purchases goods and services to support that sector. IO modeling estimates the inter-industry transactions and uses those transactions to estimate the economic impacts of any change to the economy.

The IO model used in the Plan, IMPLAN, displays the economic impacts of changes in rates into four categories: employment, labor income, value added, and output. Employment is the number of jobs gained or lost. Labor income involves the increase in salaries and wages for current and newly gained or lost employees. Value added, similar to Gross Domestic Product (GDP), is the payment to labor and capital used in production of a particular industry. Total output is the total value of the revenues, sales or value of output.

IO models are made up of matrices of multipliers between each industry present in an economy. Each column shows how an industry is dependent on other industries for both its inputs to production and outputs. The tables of multipliers can be used to estimate the effects in changes in spending for various industries, household consumption, or labor income. Both positive and negative impacts can be measured using IO modeling. IO modeling produces results broken down into several categories. Each of these is described below:

- **Direct Effects** – Increased purchases of inputs used to produce final goods and services purchased by residents. Direct effects are the input values in an IO model, or first round effects.
- **Indirect Effects** – Value of inputs used by firms affected by direct effects (inputs). Economic activity that supports direct effects.
- **Induced Effects** – Results of Direct and Indirect effects (calculated using multipliers). Represents economic activity from household spending.
- **Total Effects** – Sum of Direct, Indirect, and Induced effects.
- **Total Output** – Value of all goods and services produced by industries.
- **Value Added** – Total Output less value of inputs, or the Net Benefit/Impact to an economy.
- **Employment** – Number of additional/reduced full time employment resulting from direct effects.

This study uses value added and employment figures to represent the total additional economic impact for each Project Alternative. IMPLAN has been used in this Plan to gauge the impacts on the San José metro area of retail rate reductions associated with forming SJCE. These impacts are discussed in detail below.

Increase in Disposal Income Associated with Rate Reduction Impacts

Exhibit 34 shows the effect that $23 million in rate savings will have on the San José metropolitan area economy. The $23 million rate savings represents the minimum bill savings per year achievable by SJCE once in full operation under the 10 percent more renewable scenario. Direct effects from reduced rates are expected to add 42 jobs. Indirect effects are expected to add about 26 jobs. The induced effects are expected to create approximately 33 jobs. In total, approximately 101 jobs are expected to be created in the San José area. The San José area is also projected to have a labor income impact of over $11.5 million, a total value added impact of approximately $18.6 million, and an output impact over $31.6 million. Exhibit 34 details the macroeconomics on the San José area of the anticipated SJCE customer bill reductions.

Exhibit 34 $23 Million Rate Savings Effects on the San José Economy				
Impact Type	**Employment**	**Labor Income**	**Total Value Added**	**Output**
Direct Effect	42.3	$6,748,462	$10,728,806	$19,359,765
Indirect Effect	26.1	$2,829,014	$4,335,315	$6,982,253
Induced Effect	32.6	$2,005,331	$3,505,898	$5,280,160
Total Effect	**101.0**	**$11,582,808**	**$18,570,019**	**$31,622,178**

These savings are based on the economic construct that households will spend some share of the increased disposable income on more goods and services. This increased spending on goods and services will then lead to producers either increasing the wages of their current employees or hiring additional employees to handle the increased demand. This in turn will give the employees a larger disposable income, which they spend on goods and services, and thus repeating the cycle of increased demand.

DER Development Impacts

The economic impacts of DER development are estimated using the Jobs and Economic Development Impact (JEDI) model[68]. JEDI estimates the effects of DER development on construction industries and the local economy. JEDI was initially developed by the National Renewable Energy Laboratory to demonstrate the economic benefits associated with constructing and operating wind and photovoltaic systems in the United States. JEDI has since been expanded to analyze similar economic impacts for various energy sources such as biofuels, coal, concentrating solar power, geothermal, marine and hydrokinetic power, and natural gas. A primary goal of JEDI is that it is being used as a tool for system developers, renewable energy advocates, government officials, decision makers, and others to easily identify the local economic impacts associated with constructing and operating these systems on the economy as a whole, whether through direct and indirect effects.

Users input general information about a particular energy project, such as the project location, the type of system being installed, nameplate capacity, annual operations and maintenance costs, and others. JEDI has default but modifiable data regarding various aspects of each energy system type, such as equipment costs, tax parameters, and labor costs. JEDI then uses the input general information and the data, default or modified, to run calculations on the types of economic effects produced by the proposed project. This model projects direct job creation by industry, indirect job and business increases due to the project, projected operation costs, and more.

In order for JEDI to provide information, it must be populated with detailed data for the assumed DER project. Projected system data, type of solar cell, nameplate capacity (kW), and the number of systems. As an example of the macroeconomic activity caused by local DER deployment, this

[68] http://www.nrel.gov/analysis/jedi/

example assumes the installation of a 50 crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 50 MW. It is anticipated that SJCE will ultimately install a number of larger (5-50 MW) local solar projects such as the one described above. Exhibit 35 describes the local macroeconomic impacts of constructing a sample 50 MW local solar project in California.

Exhibit 35
Projected 50 MW Solar System Impacts on San José Economy

Description	Jobs	Earnings, $000	Output (GDP), $000
During Construction and Installation Period			
*Project Development and Onsite Labor Impacts			
Construction and Installation Labor	342.5	$22,182	
Construction and Installation Related Services	374.3	$20,007	
Subtotal	716.8	$42,189	$67,620
*Module and Supply Chain Impacts			
Manufacturing Impacts	0.0	$0	$0
Trade (Wholesale and Retail)	79.4	$4,425	$12,887
Finance, Insurance and Real Estate	0.0	$0	$0
Professional Services	53.9	$2,326	$6,908
Other Services	141.4	$15,048	$42,364
Other Sectors	317.1	$10,656	$19,428
Subtotal	591.7	$32,455	$81,587
Induced Impacts	326.7	$13,067	$39,092
Total Impacts	**1,635.3**	**$87,710**	**$188,298**
During Operating Years			
*Onsite Labor Impacts			
PV Project Labor Only	9.2	$555	$555
*Local Revenue and Supply Chain Impacts	2.7	$145	$458
*Induced Impacts	1.9	$74	$221
Total Impacts	**13.8**	**$774**	**$1,235**

Exhibit 34 shows the construction and ongoing effects of building 50, 1 MW solar power systems. It is projected that roughly 1,635 jobs will be created during construction and installation. Of this total, about 719 jobs will be directly involved in construction and installation while roughly 592 jobs will be indirectly involved with the building of the project. Induced impacts of the construction and installation will create approximately 327 jobs. These induced effects may include anything from increased employment in restaurants, retail, education, and others. Overall, the building of this one solar project is projected to create $87 million in earnings and $188 million in output (GDP) in the local economy along with 1,636 jobs during construction and 14 full-time jobs ongoing.

This section of the Plan describes the financial pro forma analysis and cost of service for SJCE. It includes estimates of staffing and administrative costs, consultant costs, power supply costs, uncollectable charges, and PG&E charges. In addition, it provides an estimate of start-up working capital and longer-term financial needs.

Sensitivity and Risk Analysis

The economic analysis provides a base case scenario for forming SJCE. This base case is predicated on numerous assumptions and estimates that influence the overall results. This section of the Plan will provide the range of impacts that could result from changes in the most significant variables for the portfolios described in the Power Supply Strategy and Cost of Service sections of this Plan. In addition, this section will address uncertainties that should be addressed and mitigated to the maximum extent possible.

We first present an overview of risks and their relative severity (Exhibit 36), followed by discussion of each factor. For variables where uncertainty is quantified key assumptions are discussed, and a reasonable range of outcomes is established. The range in variable assumptions is meant to reflect probable futures, but do not demonstrate the full scope of possible outcomes. SJCE's rate impacts are estimated using a range of likely outcomes and presented in a scenario analysis

Exhibit 36
Comparison of Risks, Mitigation Strategies, and Risk Severity

	Risk	Description	Problem	Mitigation Strategy	Likelihood of Problem	Severity of Problem	Potential to "break" SJCE
1	PG&E Rates and Surcharges	PG&E's generation rates decrease or its non-bypassable charges increase	• SJCE rates exceed PG&E • Increased customer opt-out rate	• Establish Rate Stabilization Fund • Invest in a balanced portfolio to remain agile in power market •Emphasize the value of programs, local control, and environmental impact in marketing	High – most operating CCAs in California have undergone short periods of rate competition from the incumbent IOU.	Medium - CCAs have always been able to buffer rate impacts using financial reserves, then adjust power supply to regain rate advantage.	Low – only in the event of very poor contract management by SJCE and unprecedented changes in IOU rates.
2	Regulatory Risks	Energy policy is enacted that compromises CCA competitiveness or independence	• New costs incurred • Reduced authority	• Coordination with CCA community on regulatory involvement • Hire lobbyists and regulatory representatives	Low – existing regulatory precedent makes the likelihood of state policies that severely disadvantage CCAs low.	High – a worst case scenario regulatory legislative decision limiting CCA autonomy or enforcing additional costs could hinder CCA viability.	Low – energy policy severe enough to make SJCE infeasible is very unlikely.
3	Power Supply Costs	Power prices increase at crucial time for SJCE	• SJCE rates exceed PG&E • Increased customer opt-out rate	• Long-term contracts • Draw on SJCE reserves to stabilize rates through price spike	Low – market prices are unlikely to spike enough to make SJCE financially infeasible prior to SJCE launch. From that point on, SJCE can limit its exposure through contract selection.	Medium – a poorly timed price spike combined with poor power supply contract management could require SJCE to dig into reserves or delay launch.	Very low
4	PG&E RPS Share	PG&E's RPS or GHG-free power portfolio grows	Increased customer opt-out rate	• Increase renewable power portfolio • Emphasize rates and local programs in marketing	Medium – PG&E's power portfolio is dynamic and could change rapidly as a	Low – SJCE will have capability to increase renewable energy purchases to match or	Very Low – SJCE is highly likely to respond

		to match or exceed SJCE's			result of other CCA departures.	exceed PG&E if the event occurs. In addition, SJCE will promote other benefits of its service to customers.	effectively if this occurs.
5	Availability of RPS/GHG-free power	Unexpectedly high market demand or loss of supply of renewable resources	• SJCE unable to provide target power products	• Shift emphasis to GHG-free or RPS resources depending on availability • Secure long-term contracts • Invest in local renewable resources	Low – power procurement providers report a plethora of RPS and GHG-free bids available on the market.	Medium – if SJCE were unexpectedly unable to procure enough RPS or GHG-free power, it could emphasize other program strengths to retain customers until new resources came online.	Very Low – negligible chance of occurring.
6	Financial Risks	SJCE is unable to acquire desired financing or credit	• Slower or delayed program launch • Unable to build generation projects	• Adopt gradual program roll-out • Establish Rate Stabilization Fund • Minimize overhead costs	Low – CCAs have become sufficiently established in California that financing is almost certainly available.	Medium – in the event SJCE is limited in financing options, it can adopt a more conservative program design and gradual roll-out.	Very Low
7	Loads and customer participation	Unprecedented opt-out rate reduces competitiveness	• Excess power contracts • Poor margins	• Increase marketing • Reduce overhead • Expand to new customer markets • Consider merging with existing CCA	Low – as CCAs have become more common in California, and CCA marketing firms more experienced, opt-out rates have gone lower and lower.	Low – SJCE will have numerous viable options in the event they suffer unexpectedly low participation.	Very Low

PG&E Rates and Surcharges

Sensitivity analysis is conducted for two components of PG&E rates. Assumptions are described below.

Generation Rate

PG&E generation rates are projected to increase on average by 2.8 percent per year over the next 10 years based on the projected market prices, PG&E's resource mix and renewable resource growth rates. To explore the impact in the case that PG&E's generation rate changes significantly relative to SJCE generation cost, PG&E's generation cost was modeled in the high and low case by incorporating the expected range of market and renewable resource costs (see Exhibit 31). This results in PG&E's power supply average annual growth rate in the high case of 5.5 percent and in the low case of 1.1 percent.

PCIA

The level of the PCIA will impact the cost competiveness of SJCE. In order to be cost-effective, SJCE power supply costs plus PCIA, and other surcharges, must be lower than PG&E's generation rates. Many factors influence the PCIA but primarily the PCIA is determined by the cost of power contracts and the cost to PG&E of the departing load. Uncertainties surrounding the PCIA include methodology assumptions unique to PG&E as well as to what degree previously acquired power contracts can be retired. The potential for the PCIA to increase sharply occurs when PG&E must sell previously contracted power at times when wholesale power prices are much lower. The PCIA also has potential to decrease since it reflects PG&E's own resources and signed contracts obtained prior to load departure; once the contracts expire, the related PCIA will disappear. Therefore, over time, the PCIA will vary, but it is expected that it will decline as market prices increase and grandfathered contracts expire.

Forecasting the PCIA is difficult since key inputs are heavily redacted from the rate filings and regulatory changes can significantly impact the PCIA. The uncertainty associated with forecast PCIA rates is modeled considering historic PCIA increases as well as the methodology used for the PCIA calculation where contracts are retired over time.

In the high case it was assumed that the PCIA would increase by 25 percent in 2018 and then by 2 percent per year after. The high case assumes that market prices remain low and that PG&E must sell newly acquired power contracts at a loss. The high case assumes that the PCIA rate increase will not be on the same level of the increase recently experienced due to already low market prices, and the low probability of significant decreases, as well as the relatively higher PCIA currently in effect compared with pre-2016 rates. For the low case, it was assumed that the PCIA decreases by 2 percent per year due to the expiration of contracts and/or increased market prices.

Regulatory Risks

There are numerous factors that could impact PG&E's rates in addition to the market price impacts described above. Regulatory changes, plant or technology retirements or additions, and the long-term impact of the Diablo Canyon closure all can impact PG&E's rates in the future. Regulatory issues continue to arise that may impact the competitiveness of SJCE. The impact of these factors is difficult to assess and model quantitatively. However, California's operating CCAs have worked hard to address any potentially detrimental changes through effective lobbying and technical support.

New legislation can also impact SJCE. For example, new legislation that recently affected CCAs is SB 350. The CCA-specific changes reflected in SB 350 are generally positive, providing for ongoing autonomy with regard to resource planning and procurement. CCAs must be aware, however, of the long-term contracting requirement associated with renewable energy procurement.

Regulatory risks also include the potential for utility generation costs to be shifted to non-bypassable and delivery charges. An example of such a risk is PG&E's recent proposal to retire the Diablo Canyon Nuclear Power Plant and replace the retired generating capacity with energy efficiency and renewable resources. As part of this plan, PG&E proposed instating a new non-bypassable charge to recover costs associated with all the new procurement. At this time, it is unclear how the Commission will rule on their proposal.

In addition, there is a risk that additional capacity resource costs are pushed onto CCAs via the Cost Allocation Mechanism (CAM). SJCE will need to continually monitor and lobby at the Federal, State and local levels to ensure fair and equitable treatment related to CCA charges.

Power Supply Costs

Natural gas-fired generation is predominantly used as the marginal resource within the state's dispatch order. Therefore, wholesale power supply costs (market) are driven largely by natural gas prices. In addition, SJCE's power supply mix has been modeled according to different levels of renewable energy. Renewable energy costs are forecast for the base case; however, several factors could influence future renewable energy costs including locational factors for new facilities, transmission costs, technology advancements, changes in renewable energy incentives, or changes in California or neighboring state RPS.

Since resource costs are based on forecast natural gas, wholesale market and renewable market prices, it is prudent to look at the sensitivity of the 20-year levelized cost calculation to fluctuations in these projections. Exhibit 37 below shows a summary of low, base, and high resource costs.

Exhibit 37
Low, Base and High 20-year Levelized Resource Costs ($/MWh)

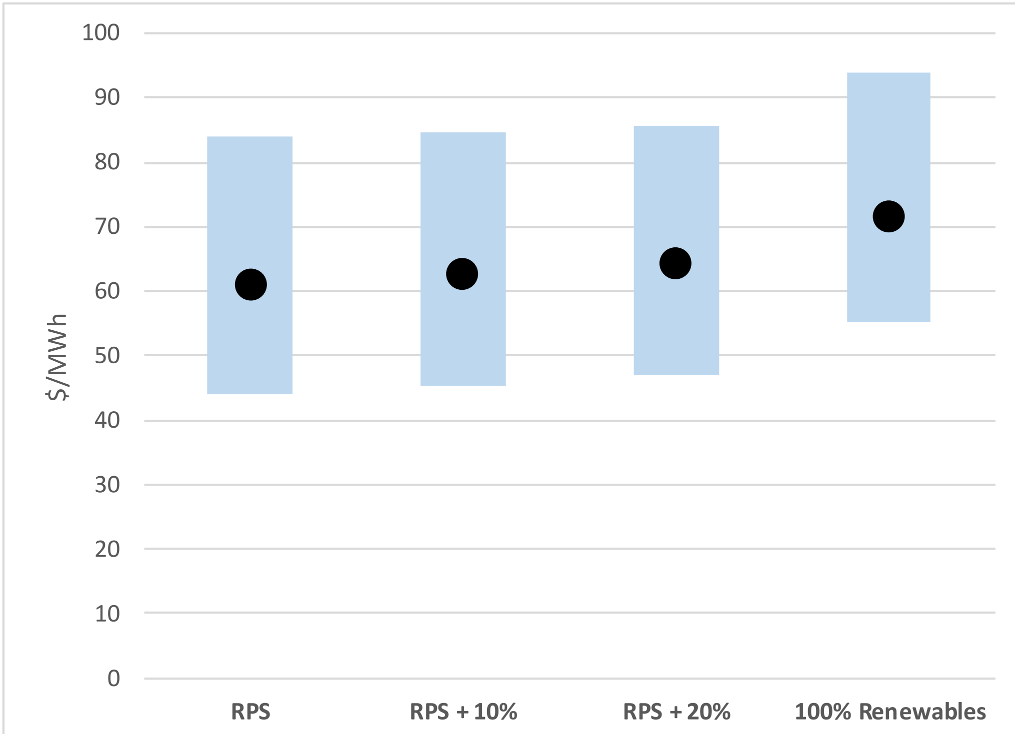
Case	Market PPA (1)	Portfolio 1 Match PG&E Renewables	Portfolio 2 PG&E + 10% Renewables	Portfolio 3 PG&E + 20% Renewables	Portfolio 4 100% Renewables	Natural Gas-Fired Resources	Local Renewables
Low Case	28	32	34	35	40	45	45
Base Case	47	46	49	51	55	60	65
High Case	76	62	65	68	75	80	85

(1) Excludes GHG-free premiums included in a portion of market PPA purchases costs in order to achieve the GHG-free purchase targets shown in Exhibit 17. Premiums escalate from $6/MWh in 2018 to $12/MWh in 2037. The 20-year levelized cost of the premium is $8.3/MWh.

Market PPA, Portfolios 1 through 3, and natural gas-fired resource levelized costs are modeled based on low and high forecasts for natural gas prices. Portfolios 1 through 4 and local renewable levelized cost scenarios are modeled for low and high renewable costs. The base case renewable energy costs are based on the cost of PPAs currently being executed in the region. The low case renewable energy costs are based on an assumption that the costs of renewable generating projects will, as expected, continue to decline and SJCE will, over time, layer in PPAs sourced to the lower cost renewable resources that will be developed over the next five to ten years. The high case renewable energy costs are based on an assumption that SJCE is not able to secure PPAs sourced to relatively new and lower cost renewable resources but, rather, signs PPAs sourced to older renewable resources with higher costs. The renewable costs in this case reflect the costs of renewable resources that were developed three to five years or more ago.

The 20-year levelized costs of each portfolio has been calculated using the range of resource costs shown above. The base case costs are depicted by the black dots in Exhibit 38.

Exhibit 38
Sensitivity of Portfolio 20-year Levelized Costs



Portfolio 4, which relies on renewable energy purchases to serve all retail loads, has the highest projected costs that range from a low of $55/MWh to a high of $94/MWh. The likelihood of renewable project costs increasing to the point that 20-year levelized costs of renewable purchases is near $62/MWh (the high case under Portfolio 1) seems unlikely. All signs point to decreases in solar equipment costs on a $/watt basis. There have been significant decreases in solar costs over the past few years. Given the financial incentives targeted at the solar industry as well as the continuing advances in technology, it seems very unlikely that solar costs will increase over the next 10 to 20 years.

The potential for market PPA prices to increase to the high case of $76/MWh has a much higher likelihood. Wholesale market prices are dependent on many factors the most notable of which are natural gas prices. Natural gas prices are at historic lows and wholesale market prices have followed. However, natural gas prices are subject to variety of local, national and international forces that could alter the current market place. For one, increased regulation of the natural gas industry with respect to the deployment of fracking technology could cause decreases in natural gas supplies and commensurate increases in natural gas prices. If natural gas prices increased, it is highly likely that electric wholesale market prices would also increase. Increased costs associated with carbon taxes and/or carbon cap and trade programs could also cause upward pressure on wholesale market prices.

When evaluating risks, it is important to note that power supply costs are approximately 60 percent of the total costs, PG&E non-by-passable charges account for 25 percent and operating costs account for 15 percent of total SJCE revenue requirement.

PG&E RPS Portfolio

There are several factors that may impact the share of renewable energy in PG&E's portfolio over the next decade. First, PG&E recently proposed plans to close their Diablo Canyon Nuclear Power Plant and to replace its generation capacity with a combination of energy efficiency and renewable energy[69]. Substantial investment in energy efficiency would reduce PG&E's total load, increasing the effective share of renewables from current contracts. Additional investments in renewables for the remainder of the Diablo plant's generating capacity would compound this trend.

Second, customers departing PG&E for CCA service throughout PG&E territory will have the effect of shrinking PG&E's load, thereby increasing the share of renewables made up by PG&E's current RPS contracts. Finally, PG&E could begin striving to compete with CCAs in terms of the environmental impact of its power portfolio. In combination, these forces could drive up the share of renewable energy in PG&E's power mix to match or exceed SJCE's planned power mix. Left unchecked, these trends could compromise SJCE's advantage over PG&E in its environmental impact.

However, there are several factors that mitigate this risk. First, PG&E's current renewable power contracts are grossly above current market price, as evidenced by the current high PCIA rates. As these current contracts grow to represent a larger share of PG&E's portfolio, they will simultaneously become less cost competitive. Second, replacing the power from the Diablo Canyon Nuclear Power Plant represents a risk to PG&E as well as SJCE. PG&E may find its massive energy efficiency projects to be slower or more expensive than expected. In addition, PG&E's track record for acquiring well-priced renewable contracts is poor, so their alternative strategy may not increase their competitiveness either. Finally, SJCE will have the option to acquire more renewable energy in response to changes in PG&E's portfolio.

Availability of Renewable and GHG-Free Resources

One of the most important goals of SJCE is to provide power to its customers that is cleaner than that provided by PG&E. As part of that goal, SJCE is projecting to increase the amount of renewable resources in its resource portfolio, while matching or exceeding PG&E's 59 percent share of GHG-free resources.

[69] https://www.pge.com/includes/docs/pdfs/safety/dcpp/JointProposal.pdf

The primary risk associated with this strategy is lack of sufficient renewable resources at prices that will keep SJCE competitive with PG&E. The current market has sufficient renewable resources available. Utilities that submit requests for renewable power supply receive bids that far exceed the requested amounts at prices that are very competitive. As RPS requirements and the share of renewable resources in CCA portfolios are increasing, competition for renewable resources could increase. However, it is important to note that the total load has not changed because customers shift to a CCA, the renewable resource timeline may just have accelerated until targets have been reached. Increased competition will result in increased prices once supply cannot meet the demand, resulting in increased development of renewable resources. In addition, the CCAs will have the opportunity to aid in the development of renewable resources by fostering local resource development.

Financial Risks

Starting a new venture carries financial risks that will have to be considered before proceeding with a CCA. Depending on the organization structure, the City may take on the financial obligations of the CCA. These include establishing start-up financing, working capital funding such as lines of credit, and entering into contracts with suppliers and consultants. Other Cities have protected their General Funds by establishing JPAs or lockbox arrangements with vendors.

However, SJCE can manage many of the financial risks associated with the uncertainty surrounding a CCA start-up. While the goal is to provide clean power competitively with PG&E, the most important consideration to the City is that SJCE can increase rates if needed to ensure sufficient revenues are collected to meet costs. In addition, SJCE can plan carefully by minimizing staff initially and only growing as fast as the size of the CCA can support, thus minimizing the fixed costs of operating the CCA.

SJCE will need to manage the financial risk associated with power supply costs by managing power market and load exposure by prudent hedging and power portfolio management. In addition, the establishment of rate stabilization reserves and sufficient working capital can mitigate financial risks to the City and to customers. The success of existing CCAs in managing the financial challenges of a CCA start-up and setting rates that are competitive with PG&E can be a valuable guide for SJCE.

Loads and Customer Participation Rates

The Plan bases the load forecasts on expected load growth, load profiles, and participation rates. In order to evaluate the potential impact of varying loads, low, medium, and high load forecasts have been developed for the sensitivity analysis. PG&E made available load shape profiles by customer class for the climate zone applicable to SJCE. These load profiles were applied to all customer loads.

Another assumption that can impact the costs of SJCE is the overall SJCE customer participation rates. This Plan uses a conservative participation rate of 85 percent for residential customers and 75 percent for non-residential customers as its base case. A higher participation rate, such as has been experienced by all of California's operating CCAs to date, will increase energy sales relative to the base case and decrease the fixed costs paid by each customer. On the other hand, a reduced participation rate will increase the fixed costs to SJCE participants.

Sensitivity to changes in projected loads has been tested for the high and low load forecast scenarios. For the sensitivity analysis, the high case assumes an additional 10 percent participation rate, while the low case assumes the participation rate is reduced by 25 percent. The low case assumes a 0 percent growth in energy and customers after 2018, while the high scenario assumes a 2.5 percent growth in energy and customers.

The experience of existing CCAs suggest that only a small number of customers opt-out. Once the CCA is operating, the number of customers switching back to the incumbent IOU have also been very low. In order to mitigate the potential switching of customers, it will be important for SJCE to implement prudent power supply strategies to address potential load swings from changes in participation and weather uncertainty, plus establish a rate stabilization fund. Keeping rates low as well as providing excellent customer service will lead to strong customer retention.

Sensitivity Results

Exhibit 39 provides the results of the sensitivity analysis for the PG&E +10% renewable scenario, which is the most likely portfolio for SJCE to pursue initially given its goals.

Exhibit 39
10% more than PG&E Portfolio Sensitivity
10-year Levelized Average System Rate (cents per kWh)

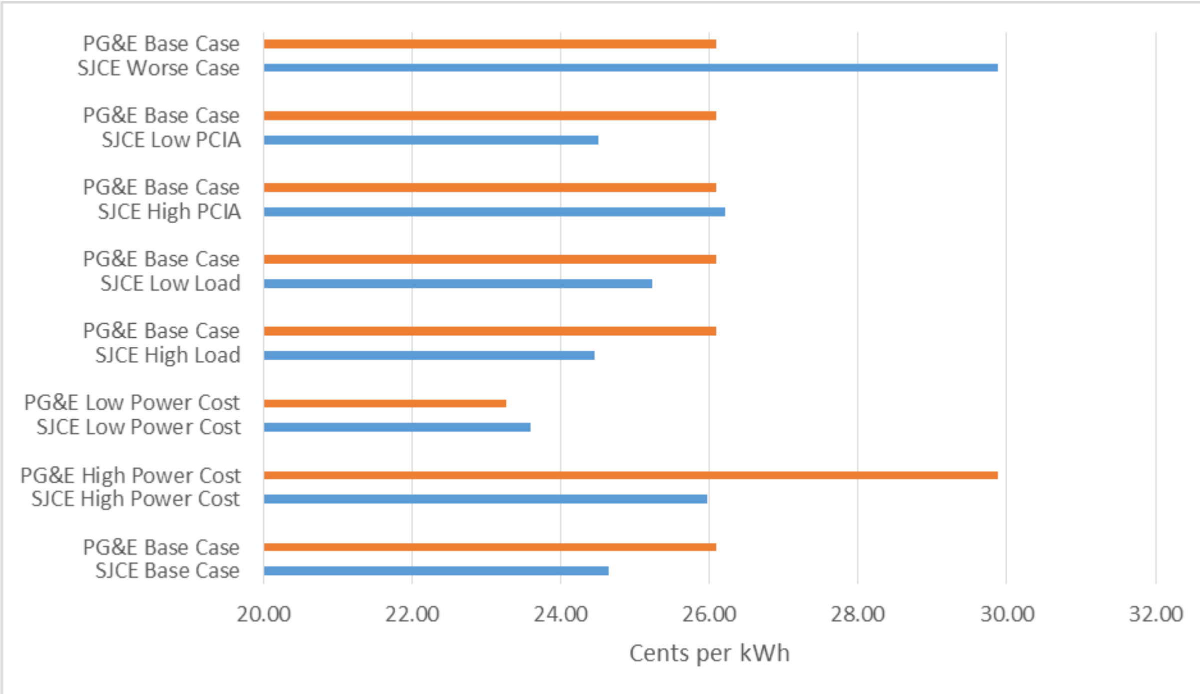


Exhibit 39 provides a comparison of the average system rate under several scenarios. This sensitivity shows that decreases in the market price is a significant risk to SJCE since it results in a higher PCIA to SJCE. Another risk to SJCE is if the PCIA increases over 25 percent in 2018 and continues to increase by 2 percent per year. Finally, SJCE's rates could be higher than PG&E's under a perfect storm scenario (Worst Case, Exhibit 39). The perfect storm is where SJCE does not achieve sufficient customer participation, SJCE power supply costs are high, and PG&E charges a high PCIA.

Wholesale market prices for natural gas/electricity are currently at all-time lows. The probability of these market prices decreasing significantly from current levels is low. In addition, SJCE will need to manage its supply portfolio so that it is not exposed to unmanageable risks associated with power costs.

While SJCE will not be able to impact PG&E's generation rates, SJCE does have opportunity to monitor and actively opine on the costs and methodology used to allocated non-bypassable costs to CCAs in PG&E's service area. Given recent history, this task will be shared with other CCAs and is an important and time consuming task that can mitigate the impact on SJCE's costs. The PCIA is at a historic high, however, the design of the PCIA implies that the PCIA will decrease over time as PG&E's high-cost contracts are expire and market prices increase. The only caveat is that there are regulatory and legislative pressures to continue adding costs to the PCIA calculation.

However, the PCIA level should be fairly stable going forward as regulatory remedies are in play to stabilize the PCIA and the CCA vigilance in this area has increased markedly.

This Plan assumes a relatively high customer opt-out percentage (15 percent for residential customers and 25 percent for non-residential customers) compared to the more modest opt-out rates experienced by California's actively operating CCAs, which is closer to 5 percent. While there is a possibility that SJCE does not reach the projected participation rates, careful monitoring and planning can reduce the potential impact of low loads.

SJCE should also consider implementing a rate stabilization fund so that short-term events that result in lower PG&E rates compared with SJCE's rates can be mitigated with reserves rather than by rate increases. Reserves will help SJCE remain competitive and will provide rate stabilization for customers.

Summary and Recommendations

SJCE Goals and Alternatives

This Business Plan was created based on several assumptions about the goals of a potential CCA in the City of San José. Before proceeding to form and launch this CCA, the City should carefully weigh these goals and ensure they are consistent with City priorities. As part of that process, the City may wish to add additional program goals to the list or refine existing goals. To facilitate that discussion, we provide four additional program goals for City officials to evaluate. These goals are based on discussions with City staff and from the plans of other CCAs.

Economic Development

Reinvesting CCA income into local economic development projects and programs has been a central aim of many currently operating CCAs in California. In addition, economic development projects can serve as a strong differentiator between PG&E's service and SJCE's. As discussed in the Business Plan, local economic development incentives can include programs such as a special economic development rate to encourage manufacturers to site in San José or targeted incentives for energy cost savings.

Risk Management

As is discussed in the Sensitivity and Risks Analysis section, forming a CCA will not be without financial risks. To address this issue, SJCE could consider identifying risk management as a central objective of its program. One way to implement such a goal would be hire an independent risk management consultant to evaluate the market risks and possible risk mitigation strategies. Such a consultant could be specifically focused on evaluating risks in SJCE's third-party power portfolio. Such an advisor role can also be useful as guidance on any staff development of risk management policies and periodic checks on those efforts.

Renewable Portfolio Targets

The City could consider benchmarking its renewable energy objective off of the statewide RPS requirement or PG&E's planned power mix (i.e. the power product strategy outlined in this Business Plan) to ensure a less volatile program goal than if the City benchmarked off of PG&E's *actual* renewable portfolio year-by-year. PG&E's share of renewable power could change rapidly over the next decade (see Risks discussion). State RPS requirements are likely to change more slowly than PG&E's planned power supply. However, SJCE will inherently be in competition with PG&E on its power products. Therefore, program goals that benchmark on PG&E can be useful for ensuring a strong differentiation between providers. City decision-makers should weigh these tradeoffs.

GHG-Free Power Targets

In addition to considering refining its RPS goals, San José could set an additional objective of how much of its power supply will be GHG-free. Ensuring that SJCE's power supply is both more renewable (RPS) and represents a lower contribution to climate change will be critical to providing a power product that is competitive with PG&E.

Rate Impacts and Comparisons

The first impact associated with forming SJCE will be lower electricity bills for SJCE customers. SJCE customers should see no obvious changes in electric service other than the lower price and increased procurement of renewable power. Customers will pay the power supply charges set by SJCE and no longer pay the higher costs of PG&E power supply.

Given this Plan's findings, SJCE's rate setting can establish a goal of providing rates that are lower than the equivalent rates offered by PG&E even under the PG&E RPS + 10% and PG&E RPS + 20% power portfolios. The projected SJCE and PG&E rates are illustrated in Exhibit 40. For this Plan, it has been assumed that the projected rate decrease is applied uniformly across all rate classes. Once established, it will be up to the SJCE governing body and staff to develop rates for each rate class that reflects cost of service.

Exhibit 40
Indicative Rate Comparison in $/kWh

Rate Class	2017 PG&E Bundled Rate*	Indicative SJCE RPS Bundled Rate	Indicative SJCE 10% more Green Bundled Rate	Indicative SJCE 20% more Green Bundled Rate	Indicative SJCE 100% Green Bundled Rate
Residential	0.19971	0.1913	0.1921	0.1953	0.2063
Small Commercial	0.22515	0.2157	0.2166	0.2202	0.2326
Medium Commercial	0.20053	0.1921	0.1929	0.1961	0.2071
Large Commercial	0.17618	0.1688	0.1695	0.1723	0.1820
Street Lights	0.21785	0.2087	0.2096	0.2131	0.2250
Standby	0.14608	0.1399	0.1405	0.1429	0.1509
Agriculture	0.17606	0.1687	0.1694	0.1722	0.1819
Industrial	0.13985	0.1340	0.1345	0.1368	0.1445
Total	**0.18779**	**0.1799**	**0.1807**	**0.1837**	**0.1940**
Initial Rate Savings in 2019 from PG&E Bundled Rate		**4.2%**	**3.8%**	**2.2%**	**-3.4%**
Rate Savings After Fully Operational		**4.8 – 9.4%**	**4.5 – 8.9%**	**2.7 – 7.2%**	**-2.7 – 1.3%**

*PG&E bundled average rate based on PG&E's ERRA 2017 Draft Filing

Once SJCE gives notice to PG&E that it will commence service, SJCE customers will not be responsible for costs associated with PG&E's future electricity procurement contracts or power plant investments.[70] This is a distinct advantage to SJCE customers as they will now have local control of power supply costs through SJCE.

Renewable Energy and Greenhouse Gas Impacts

A second consequence of forming SJCE will be an increase in the proportion of energy generated and supplied by renewable, GHG-free resources. Based on the power supply strategy described previously, GHG emission reductions due to additional renewable resource procurement resulting from the formation of SJCE are estimated to range from 152,000 to 264,000 MT CO_2e per year in 2019 assuming a 10 percent higher than PG&E RPS target is achieved. For the 20% higher than PG&E, the estimated range of GHG emission savings is 304,000 to 528,000 MT CO_2e per year in 2019. The baseline for comparison is the projected resource mix used by PG&E in the same time period. Exhibit 41 details these reductions.

Exhibit 41
Comparison of GHG Reduction by SJCE

	10% Additional Renewable	20% Additional Renewable
2019 Load (GWH)	3,769	3,769
SJCE Additional Renewable (GWH)	377	754
CO2 reduction – Low (Metric Tons of CO_2e)	152,267	304,535
CO2 reduction – High (Metric tons of CO_2e)	263,830	527,660

Economic Development Impacts

The third consequence of forming SJCE will be enhanced local economic development. This can occur as a result of city-wide electric rate savings and the increased retention of and growth in manufacturing jobs and other energy intensive industries. Exhibit 41 shows the effects $23 million in rate savings could have on the San José economy. The $23 million rate savings represents the minimum bill savings per year achievable by SJCE once in full operation. Direct effects from reduced rates are expected to add 42 jobs. Indirect effects are expected to add about 26 jobs. The induced effects of the project create approximately 33 jobs. In total, approximately 101 jobs are expected to be created in the San José area. The San José area is also projected to have a labor income impact of over $11.5 million, a total value added impact of approximately $18.6 million, and an output impact over $31.6 million. Exhibit 42 details the macroeconomics on the San José area of the anticipated SJCE customer bill reductions.

[70] CCAs may be liable for a share of unbundled stranded costs from new generation, but would then receive associated Resource Adequacy credits.

Exhibit 42 $23 Million Rate Savings Effects on the San José Economy				
Impact Type	**Employment**	**Labor Income**	**Total Value Added**	**Output**
Direct Effect	42.3	$6,748,462	$10,728,806	$19,359,765
Indirect Effect	26.1	$2,829,014	$4,335,315	$6,982,253
Induced Effect	32.6	$2,005,331	$3,505,898	$5,280,160
Total Effect	101.0	$11,582,808	$18,570,019	$31,622,178

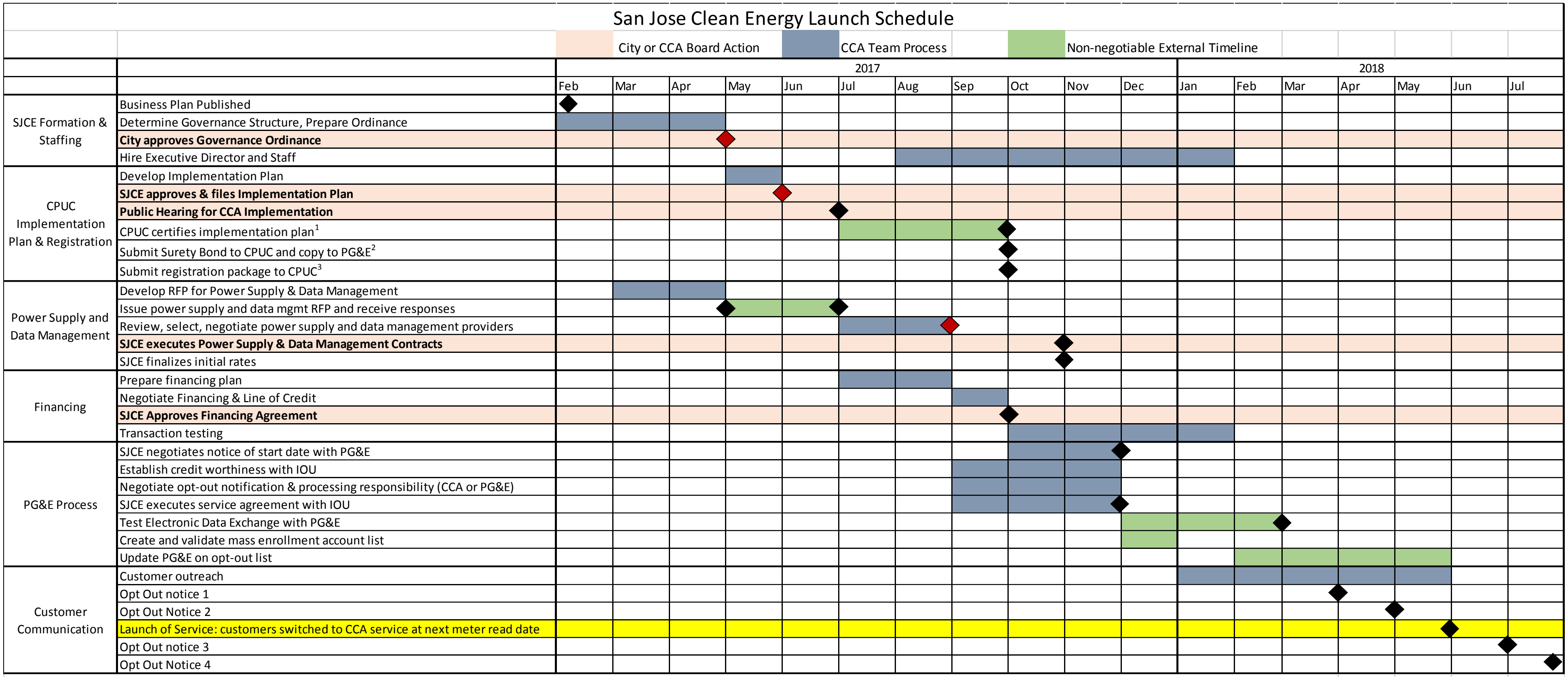
These savings are based on the economic construct that households will spend some share of the increased disposable income on more goods and services. This increased spending on goods and services will then lead to producers either increasing the wages of their current employees or hiring additional employees to handle the increased demand. This in turn will give the employees a larger disposable income which they spend on goods and services and thus repeating the cycle of increased demand.

In addition to increased economic activity due to electric bill savings, potential local projects can also create job and economic growth in the local economy. As an example of the macroeconomic activity caused by local DER deployment, this Plan assumes the installation of fifty crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 50 MW. Overall, the building of this one solar project is projected to create $87 million in earnings and $188 million in output (GDP) in the local economy along with 1,636 jobs during construction and 14 full-time jobs ongoing. It is anticipated that SJCE will ultimately install a number of larger local solar projects such as the one described.

Summary

This Plan concludes that the formation of SJCE is financially prudent and will yield considerable benefits for residents and businesses in the City of San José. If SJCE elects the PG&E RPS + 10% power supply model, these benefits will include significantly lower rates for electricity than is charged by PG&E while reducing GHG emissions between 152,000 and 264,000 MT CO_2e per year in 2019 – in alignment with the initial goals set out for SJCE. In addition, the formation of SJCE is expected to lead to roughly 100 additional jobs and generate over $31 million in additional GDP, all while giving residents and businesses local control over their power supply and energy efficiency programs. Even with these stated rate savings, significant funding is still generated to support new local programs, build CCA reserves, and/or offer additional rate savings to CCA's customers down the road. There are risks associated with a CCA which are manageable. On balance, the formation of a CCA for the City of San José is financially feasible and results in beneficial environmental/economic impacts.

Appendix A – Projected Schedule



[1]Represents maximum possible duration for CPUC review of implementation plan, [2]Contingent on completing financing agreement, [3]Contingent on completion of service agreement with PG&E

San Jose Community Choice Aggregation
Customer & Load Data
Portfolio - RPS

Load Data	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Customer Accounts														
Domestic	-	161,295.98	277,482.08	279,424.45	281,380.42	283,350.09	285,333.54	287,330.87	289,342.19	291,367.58	293,407.16	295,461.01	297,529.23	299,611.94
Commercial	-	9,696.82	18,920.76	19,053.21	19,186.58	19,320.89	19,456.13	19,592.33	19,729.47	19,867.58	20,006.65	20,146.70	20,287.73	20,429.74
Industrial	-	231.03	1,183.38	1,191.66	1,200.00	1,208.40	1,216.86	1,225.38	1,233.95	1,242.59	1,251.29	1,260.05	1,268.87	1,277.75
Lighting & Traffic Control	-	1,320.26	2,716.50	2,735.51	2,754.66	2,773.95	2,793.36	2,812.92	2,832.61	2,852.44	2,872.40	2,892.51	2,912.76	2,933.15
Agricultural	-	2.43	14.65	14.76	14.86	14.96	15.07	15.17	15.28	15.39	15.49	15.60	15.71	15.82
Total Customers		172,547	300,317	302,420	304,537	306,668	308,815	310,977	313,154	315,346	317,553	319,776	322,014	324,268
Energy Sales (KWh)														
Domestic	-	946,025,173	1,552,165,639	1,563,030,799	1,573,972,014	1,584,989,818	1,596,084,747	1,607,257,340	1,618,508,142	1,629,837,699	1,641,246,563	1,652,735,288	1,664,304,435	1,675,954,567
Commercial	-	302,811,887	929,407,882	935,913,737	942,465,133	949,062,389	955,705,826	962,395,767	969,132,537	975,916,465	982,747,880	989,627,115	996,554,505	1,003,530,386
Industrial	-	256,831,034	1,347,425,967	1,356,857,949	1,366,355,955	1,375,920,446	1,385,551,889	1,395,250,753	1,405,017,508	1,414,852,630	1,424,756,599	1,434,729,895	1,444,773,004	1,454,886,415
Lighting & Traffic Control	-	5,579,155	34,789,702	35,033,230	35,278,463	35,525,412	35,774,090	36,024,509	36,276,680	36,530,617	36,786,331	37,043,836	37,303,143	37,564,265
Agricultural	-	182,397	1,223,799	1,232,366	1,240,992	1,249,679	1,258,427	1,267,236	1,276,106	1,285,039	1,294,035	1,303,093	1,312,214	1,321,400
Total Energy Sales (KWh)		1,511,429,646	3,865,012,990	3,892,068,081	3,919,312,557	3,946,747,745	3,974,374,979	4,002,195,604	4,030,210,973	4,058,422,450	4,086,831,407	4,115,439,227	4,144,247,302	4,173,257,033

San Jose Community Choice Aggregation
Financial Proforma
Portfolio - RPS

CCE Operating Costs	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Power Supply		$75,075,737	$214,170,172	$225,825,329	$232,424,224	$239,087,227	$246,098,048	$252,950,934	$259,889,012	$267,721,552	$274,851,096	$282,077,435	$289,597,053	$297,514,552
Billing & Data Management		$2,592,169	$4,504,761	$4,536,294	$4,568,048	$4,600,024	$4,632,224	$4,664,650	$4,697,303	$4,730,184	$4,763,295	$4,796,638	$4,830,214	$4,864,026
PG&E Fees		$1,267,182	$2,249,641	$2,310,697	$2,373,409	$2,437,823	$2,503,986	$2,571,944	$2,641,747	$2,713,444	$2,787,086	$2,862,728	$2,940,422	$3,020,225
Technical Services		$630,000	$1,120,000	$1,087,320	$1,002,946	$1,023,005	$1,043,465	$1,064,334	$1,085,621	$1,107,333	$1,129,480	$1,152,069	$1,175,111	$1,198,613
Staffing		$2,001,267	$3,837,839	$3,952,974	$4,071,563	$4,193,710	$4,319,521	$4,449,107	$4,582,580	$4,720,058	$4,861,659	$5,007,509	$5,157,734	$5,312,466
General & Administrative expenses		$790,000	$357,000	$312,120	$318,362	$378,851	$430,592	$395,283	$344,606	$351,498	$423,208	$486,826	$444,425	$380,473
Debt Service (CCE Bonds & Start-up Costs)		$1,170,882	$5,354,849	$5,354,849	$5,354,849	$5,354,849	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967
Start-Up Capital		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual Contribution to Reserves		$13,746,877	$26,429,776	$25,334,876	$29,462,872	$16,861,120		$0	$0	$0	$0	$0	$0	$0
New Programs Funding		$0	$0	$0	$0	$16,861,120	$38,029,842	$40,990,977	$44,151,823	$46,760,158	$50,065,305	$53,748,374	$57,450,172	$61,040,190
Uncollectibles		$639,720	$1,662,096	$1,715,762	$1,744,437	$1,774,010	$1,801,993	$1,836,457	$1,871,217	$1,910,874	$1,946,959	$1,983,697	$2,021,206	$2,060,514
Total Operating Costs		$97,913,834	$259,686,133	$270,430,221	$281,320,709	$292,571,739	$303,043,637	$313,107,652	$323,447,874	$334,199,065	$345,012,055	$356,299,243	$367,800,303	$379,575,026
Other Revenues		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement		$97,913,834	$259,686,133	$270,430,221	$281,320,709	$292,571,739	$303,043,637	$313,107,652	$323,447,874	$334,199,065	$345,012,055	$356,299,243	$367,800,303	$379,575,026
Average CCE Rate ($/kWh)		$0.1749	$0.1140	$0.1179	$0.1218	$0.1258	$0.1294	$0.1327	$0.1362	$0.1397	$0.1432	$0.1469	$0.1506	$0.1543
Average PG&E Generation Rate ($/kWh)		$0.0998	$0.1018	$0.1053	$0.1088	$0.1123	$0.1155	$0.1185	$0.1216	$0.1248	$0.1279	$0.1312	$0.1345	$0.1378
Total CCE Charges														
PG&E Non-bypassable Charges		$43,786,811	$100,824,918	$99,772,911	$98,773,937	$97,726,440	$97,186,895	$97,011,206	$96,818,510	$96,646,668	$96,392,064	$96,172,201	$95,912,225	$95,628,426
CCE Revenue Requirement		$97,913,834	$259,686,133	$270,430,221	$281,320,709	$292,571,739	$303,043,637	$313,107,652	$323,447,874	$334,199,065	$345,012,055	$356,299,243	$367,800,303	$379,575,026
Total CCE Generation Revenue Requirement		$141,700,645	$360,511,051	$370,203,132	$380,094,646	$390,298,179	$400,230,532	$410,118,858	$420,266,383	$430,845,734	$441,404,118	$452,471,444	$463,712,528	$475,203,452
Bundled PG&E Revenues		$308,259,271	$777,818,683	$804,528,994	$831,744,232	$859,796,536	$867,193,537	$893,516,155	$920,557,819	$948,530,875	$976,914,649	$1,006,342,598	$1,036,429,130	$1,067,273,911
Total CCE Customer Bill Revenues (Power Supply and Delivery)		$300,773,009	$744,865,895	$764,989,366	$785,595,379	$806,804,202	$808,267,043	$829,229,479	$850,751,667	$873,014,388	$895,573,230	$918,966,705	$942,868,471	$967,363,687
Savings		**$7,486,262**	**$32,952,787**	**$39,539,628**	**$46,148,853**	**$52,992,335**	**$58,926,494**	**$64,286,676**	**$69,806,152**	**$75,516,486**	**$81,341,419**	**$87,375,893**	**$93,560,659**	**$99,910,224**
Percent Savings		**2.4%**	**4.2%**	**4.9%**	**5.5%**	**6.2%**	**6.8%**	**7.2%**	**7.6%**	**8.0%**	**8.3%**	**8.7%**	**9.0%**	**9.4%**
Reserves		$13,746,877	$26,429,776	$25,334,876	$29,462,872	$33,722,240	$38,029,842	$40,990,977	$44,151,823	$46,760,158	$50,065,305	$53,748,374	$57,450,172	$61,040,190
Cummulative Reserves		$13,746,877	$40,176,653	$65,511,529	$94,974,401	$111,835,521	$111,835,521	$111,835,521	$111,835,521	$111,835,521	$111,835,521	$111,835,521	$111,835,521	$111,835,521

San Jose Community Choice Aggregation
Customer & Load Data
Portfolio - 10% More Renewable

Load Data	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Customer Accounts														
Domestic	-	161,295.98	277,482.08	279,424.45	281,380.42	283,350.09	285,333.54	287,330.87	289,342.19	291,367.58	293,407.16	295,461.01	297,529.23	299,611.94
Commercial	-	9,696.82	18,920.76	19,053.21	19,186.58	19,320.89	19,456.13	19,592.33	19,729.47	19,867.58	20,006.65	20,146.70	20,287.73	20,429.74
Industrial	-	231.03	1,183.38	1,191.66	1,200.00	1,208.40	1,216.86	1,225.38	1,233.95	1,242.59	1,251.29	1,260.05	1,268.87	1,277.75
Lighting & Traffic Control	-	1,320.26	2,716.50	2,735.51	2,754.66	2,773.95	2,793.36	2,812.92	2,832.61	2,852.44	2,872.40	2,892.51	2,912.76	2,933.15
Agricultural	-	2.43	14.65	14.76	14.86	14.96	15.07	15.17	15.28	15.39	15.49	15.60	15.71	15.82
Total Customers		172,547	300,317	302,420	304,537	306,668	308,815	310,977	313,154	315,346	317,553	319,776	322,014	324,268
Energy Sales (KWh)														
Domestic	-	946,025,173	1,552,165,639	1,563,030,799	1,573,972,014	1,584,989,818	1,596,084,747	1,607,257,340	1,618,508,142	1,629,837,699	1,641,246,563	1,652,735,288	1,664,304,435	1,675,954,567
Commercial	-	302,811,887	929,407,882	935,913,737	942,465,133	949,062,389	955,705,826	962,395,767	969,132,537	975,916,465	982,747,880	989,627,115	996,554,505	1,003,530,386
Industrial	-	256,831,034	1,347,425,967	1,356,857,949	1,366,355,955	1,375,920,446	1,385,551,889	1,395,250,753	1,405,017,508	1,414,852,630	1,424,756,599	1,434,729,895	1,444,773,004	1,454,886,415
Lighting & Traffic Control	-	5,579,155	34,789,702	35,033,230	35,278,463	35,525,412	35,774,090	36,024,509	36,276,680	36,530,617	36,786,331	37,043,836	37,303,143	37,564,265
Agricultural	-	182,397	1,223,799	1,232,366	1,240,992	1,249,679	1,258,427	1,267,236	1,276,106	1,285,039	1,294,035	1,303,093	1,312,214	1,321,400
Total Energy Sales (KWh)		1,511,429,646	3,865,012,990	3,892,068,081	3,919,312,557	3,946,747,745	3,974,374,979	4,002,195,604	4,030,210,973	4,058,422,450	4,086,831,407	4,115,439,227	4,144,247,302	4,173,257,033

DRAFT

San Jose Community Choice Aggregation
Financial Proforma
Portfolio - 10% More Renewable

CCE Operating Costs	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Power Supply		$78,520,386	$223,478,371	$234,666,751	$240,979,408	$247,336,445	$253,782,452	$260,479,765	$267,047,229	$274,197,541	$280,871,139	$287,596,725	$294,783,012	$302,253,806
Billing & Data Management		$2,592,169	$4,504,761	$4,536,294	$4,568,048	$4,600,024	$4,632,224	$4,664,650	$4,697,303	$4,730,184	$4,763,295	$4,796,638	$4,830,214	$4,864,026
PG&E Fees		$1,267,182	$2,249,641	$2,310,697	$2,373,409	$2,437,823	$2,503,986	$2,571,944	$2,641,747	$2,713,444	$2,787,086	$2,862,728	$2,940,422	$3,020,225
Technical Services		$630,000	$1,120,000	$1,087,320	$1,002,946	$1,023,005	$1,043,465	$1,064,334	$1,085,621	$1,107,333	$1,129,480	$1,152,069	$1,175,111	$1,198,613
Staffing		$2,001,267	$3,837,839	$3,952,974	$4,071,563	$4,193,710	$4,319,521	$4,449,107	$4,582,580	$4,720,058	$4,861,659	$5,007,509	$5,157,734	$5,312,466
General & Administrative expenses		$790,000	$357,000	$312,120	$318,362	$378,851	$430,592	$395,283	$344,606	$351,498	$423,208	$486,826	$444,425	$380,473
Debt Service (CCE Bonds & Start-up Costs)		$1,170,882	$5,354,849	$5,354,849	$5,354,849	$5,354,849	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967
Start-Up Capital		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual Contribution to Reserves		$11,491,429	$20,222,747	$19,727,190	$24,274,860	$14,489,050		$0	$0	$0	$0	$0	$0	$0
New Programs Funding		$0	$0	$0	$0	$14,489,050	$33,980,272	$37,219,746	$40,878,395	$44,302,687	$48,197,126	$52,520,265	$56,696,468	$60,878,150
Uncollectibles		$656,943	$1,708,637	$1,759,970	$1,787,213	$1,815,256	$1,840,416	$1,874,101	$1,907,008	$1,943,253	$1,977,059	$2,011,293	$2,047,136	$2,084,210
Total Operating Costs		$99,120,259	$262,833,844	$273,708,163	$284,730,657	$296,118,063	$306,716,894	$316,902,897	$327,368,454	$338,249,963	$349,194,019	$360,618,021	$372,258,489	$384,175,936
Other Revenues		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement		$99,120,259	$262,833,844	$273,708,163	$284,730,657	$296,118,063	$306,716,894	$316,902,897	$327,368,454	$338,249,963	$349,194,019	$360,618,021	$372,258,489	$384,175,936
Average CCE Rate ($/kWh)		$0.1771	$0.1154	$0.1193	$0.1233	$0.1273	$0.1309	$0.1343	$0.1378	$0.1414	$0.1450	$0.1487	$0.1524	$0.1562
Average PG&E Generation Rate ($/kWh)		$0.0998	$0.1018	$0.1053	$0.1088	$0.1123	$0.1155	$0.1185	$0.1216	$0.1248	$0.1279	$0.1312	$0.1345	$0.1378
Total CCE Charges														
PG&E Non-bypassable Charges		$43,786,811	$100,824,918	$99,772,911	$98,773,937	$97,726,440	$97,186,895	$97,011,206	$96,818,510	$96,646,668	$96,392,064	$96,172,201	$95,912,225	$95,628,426
CCE Revenue Requirement		$99,120,259	$262,833,844	$273,708,163	$284,730,657	$296,118,063	$306,716,894	$316,902,897	$327,368,454	$338,249,963	$349,194,019	$360,618,021	$372,258,489	$384,175,936
Total CCE Generation Revenue Requirement		$142,907,070	$363,658,762	$373,481,074	$383,504,594	$393,844,503	$403,903,788	$413,914,102	$424,186,964	$434,896,632	$445,586,083	$456,790,223	$468,170,714	$479,804,362
Bundled PG&E Revenues		$308,259,271	$777,818,683	$804,528,994	$831,744,232	$859,796,536	$867,193,537	$893,516,155	$920,557,819	$948,530,875	$976,914,649	$1,006,342,598	$1,036,429,130	$1,067,273,911
Total CCE Customer Bill Revenues (Power Supply and Delivery)		$301,979,434	$748,013,606	$768,267,308	$789,005,327	$810,350,526	$811,940,299	$833,024,724	$854,672,247	$877,065,286	$899,755,194	$923,285,484	$947,326,657	$971,964,597
Savings		**$6,279,837**	**$29,805,077**	**$36,261,685**	**$42,738,905**	**$49,446,010**	**$55,253,238**	**$60,491,432**	**$65,885,572**	**$71,465,589**	**$77,159,455**	**$83,057,115**	**$89,102,473**	**$95,309,314**
Percent Savings		**2.0%**	**3.8%**	**4.5%**	**5.1%**	**5.8%**	**6.4%**	**6.8%**	**7.2%**	**7.5%**	**7.9%**	**8.3%**	**8.6%**	**8.9%**
Reserves		$11,491,429	$20,222,747	$19,727,190	$24,274,860	$28,978,101	$33,980,272	$37,219,746	$40,878,395	$44,302,687	$48,197,126	$52,520,265	$56,696,468	$60,878,150
Cummulative Reserves		$11,491,429	$31,714,176	$51,441,366	$75,716,226	$90,205,276	$90,205,276	$90,205,276	$90,205,276	$90,205,276	$90,205,276	$90,205,276	$90,205,276	$90,205,276

San Jose Community Choice Aggregation
Customer & Load Data
Portfolio - 20% More Renewable

Load Data	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Customer Accounts														
Domestic	-	161,295.98	277,482.08	279,424.45	281,380.42	283,350.09	285,333.54	287,330.87	289,342.19	291,367.58	293,407.16	295,461.01	297,529.23	299,611.94
Commercial	-	9,696.82	18,920.76	19,053.21	19,186.58	19,320.89	19,456.13	19,592.33	19,729.47	19,867.58	20,006.65	20,146.70	20,287.73	20,429.74
Industrial	-	231.03	1,183.38	1,191.66	1,200.00	1,208.40	1,216.86	1,225.38	1,233.95	1,242.59	1,251.29	1,260.05	1,268.87	1,277.75
Lighting & Traffic Control	-	1,320.26	2,716.50	2,735.51	2,754.66	2,773.95	2,793.36	2,812.92	2,832.61	2,852.44	2,872.40	2,892.51	2,912.76	2,933.15
Agricultural	-	2.43	14.65	14.76	14.86	14.96	15.07	15.17	15.28	15.39	15.49	15.60	15.71	15.82
Total Customers		172,547	300,317	302,420	304,537	306,668	308,815	310,977	313,154	315,346	317,553	319,776	322,014	324,268
Energy Sales (KWh)														
Domestic	-	946,025,173	1,552,165,639	1,563,030,799	1,573,972,014	1,584,989,818	1,596,084,747	1,607,257,340	1,618,508,142	1,629,837,699	1,641,246,563	1,652,735,288	1,664,304,435	1,675,954,567
Commercial	-	302,811,887	929,407,882	935,913,737	942,465,133	949,062,389	955,705,826	962,395,767	969,132,537	975,916,465	982,747,880	989,627,115	996,554,505	1,003,530,386
Industrial	-	256,831,034	1,347,425,967	1,356,857,949	1,366,355,955	1,375,920,446	1,385,551,889	1,395,250,753	1,405,017,508	1,414,852,630	1,424,756,599	1,434,729,895	1,444,773,004	1,454,886,415
Lighting & Traffic Control	-	5,579,155	34,789,702	35,033,230	35,278,463	35,525,412	35,774,090	36,024,509	36,276,680	36,530,617	36,786,331	37,043,836	37,303,143	37,564,265
Agricultural	-	182,397	1,223,799	1,232,366	1,240,992	1,249,679	1,258,427	1,267,236	1,276,106	1,285,039	1,294,035	1,303,093	1,312,214	1,321,400
Total Energy Sales (KWh)		1,511,429,646	3,865,012,990	3,892,068,081	3,919,312,557	3,946,747,745	3,974,374,979	4,002,195,604	4,030,210,973	4,058,422,450	4,086,831,407	4,115,439,227	4,144,247,302	4,173,257,033

San Jose Community Choice Aggregation
Financial Proforma
Portfolio - 20% More Renewable

CCE Operating Costs	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Power Supply		$82,075,572	$233,636,992	$244,673,422	$250,715,296	$256,838,245	$262,986,630	$269,160,727	$275,804,128	$282,083,215	$288,414,428	$294,782,222	$301,593,588	$308,185,498
Billing & Data Management		$2,592,169	$4,504,761	$4,536,294	$4,568,048	$4,600,024	$4,632,224	$4,664,650	$4,697,303	$4,730,184	$4,763,295	$4,796,638	$4,830,214	$4,864,026
PG&E Fees		$1,267,182	$2,249,641	$2,310,697	$2,373,409	$2,437,823	$2,503,986	$2,571,944	$2,641,747	$2,713,444	$2,787,086	$2,862,728	$2,940,422	$3,020,225
Technical Services		$630,000	$1,120,000	$1,087,320	$1,002,946	$1,023,005	$1,043,465	$1,064,334	$1,085,621	$1,107,333	$1,129,480	$1,152,069	$1,175,111	$1,198,613
Staffing		$2,001,267	$3,837,839	$3,952,974	$4,071,563	$4,193,710	$4,319,521	$4,449,107	$4,582,580	$4,720,058	$4,861,659	$5,007,509	$5,157,734	$5,312,466
General & Administrative expenses		$790,000	$357,000	$312,120	$318,362	$378,851	$430,592	$395,283	$344,606	$351,498	$423,208	$486,826	$444,425	$380,473
Debt Service (CCE Bonds & Start-up Costs)		$1,170,882	$5,354,849	$5,354,849	$5,354,849	$5,354,849	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967
Start-Up Capital		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual Contribution to Reserves		$12,744,168	$22,604,176	$22,782,253	$28,130,084	$16,807,044		$0	$0	$0	$0	$0	$0	$0
New Programs Funding		$0	$0	$0	$0	$16,807,044	$39,423,098	$43,676,356	$47,760,033	$52,581,175	$57,343,977	$62,573,956	$67,684,581	$73,320,437
Uncollectibles		$674,719	$1,759,430	$1,810,003	$1,835,892	$1,862,765	$1,886,436	$1,917,506	$1,950,792	$1,982,682	$2,014,776	$2,047,221	$2,081,188	$2,113,868
Total Operating Costs		$103,945,960	$275,424,687	$286,819,931	$298,370,449	$310,303,359	$321,409,919	$332,083,874	$343,050,775	$354,453,554	$365,921,876	$377,893,136	$390,091,231	$402,579,573
Other Revenues		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement		$103,945,960	$275,424,687	$286,819,931	$298,370,449	$310,303,359	$321,409,919	$332,083,874	$343,050,775	$354,453,554	$365,921,876	$377,893,136	$390,091,231	$402,579,573
Average CCE Rate ($/kWh)		$0.1857	$0.1209	$0.1250	$0.1292	$0.1334	$0.1372	$0.1408	$0.1444	$0.1482	$0.1519	$0.1558	$0.1597	$0.1637
Average PG&E Generation Rate ($/kWh)		$0.0998	$0.1018	$0.1053	$0.1088	$0.1123	$0.1155	$0.1185	$0.1216	$0.1248	$0.1279	$0.1312	$0.1345	$0.1378
Total CCE Charges														
PG&E Non-bypassable Charges		$43,786,811	$100,824,918	$99,772,911	$98,773,937	$97,726,440	$97,186,895	$97,011,206	$96,818,510	$96,646,668	$96,392,064	$96,172,201	$95,912,225	$95,628,426
CCE Revenue Requirement		$103,945,960	$275,424,687	$286,819,931	$298,370,449	$310,303,359	$321,409,919	$332,083,874	$343,050,775	$354,453,554	$365,921,876	$377,893,136	$390,091,231	$402,579,573
Total CCE Generation Revenue Requirement		$147,732,771	$376,249,605	$386,592,842	$397,144,386	$408,029,800	$418,596,813	$429,095,079	$439,869,285	$451,100,223	$462,313,940	$474,065,337	$486,003,456	$498,207,999
Bundled PG&E Revenues		$308,259,271	$777,818,683	$804,528,994	$831,744,232	$859,796,536	$867,193,537	$893,516,155	$920,557,819	$948,530,875	$976,914,649	$1,006,342,598	$1,036,429,130	$1,067,273,911
Total CCE Customer Bill Revenues (Power Supply and Delivery)		$306,805,135	$760,604,449	$781,379,076	$802,645,119	$824,535,822	$826,633,324	$848,205,701	$870,354,569	$893,268,877	$916,483,051	$940,560,599	$965,159,398	$990,368,234
Savings		**$1,454,136**	**$17,214,234**	**$23,149,917**	**$29,099,113**	**$35,260,714**	**$40,560,213**	**$45,310,454**	**$50,203,251**	**$55,261,998**	**$60,431,598**	**$65,782,000**	**$71,269,731**	**$76,905,677**
Percent Savings		**0.5%**	**2.2%**	**2.9%**	**3.5%**	**4.1%**	**4.7%**	**5.1%**	**5.5%**	**5.8%**	**6.2%**	**6.5%**	**6.9%**	**7.2%**
Reserves		$12,744,168	$22,604,176	$22,782,253	$28,130,084	$33,614,087	$39,423,098	$43,676,356	$47,760,033	$52,581,175	$57,343,977	$62,573,956	$67,684,581	$73,320,437
Cummulative Reserves		$12,744,168	$35,348,344	$58,130,597	$86,260,681	$103,067,725	$103,067,725	$103,067,725	$103,067,725	$103,067,725	$103,067,725	$103,067,725	$103,067,725	$103,067,725

San Jose Community Choice Aggregation
Customer & Load Data
Portfolio 100% Renewable

Load Data	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Customer Accounts														
Domestic	-	161,295.98	277,482.08	279,424.45	281,380.42	283,350.09	285,333.54	287,330.87	289,342.19	291,367.58	293,407.16	295,461.01	297,529.23	299,611.94
Commercial	-	9,696.82	18,920.76	19,053.21	19,186.58	19,320.89	19,456.13	19,592.33	19,729.47	19,867.58	20,006.65	20,146.70	20,287.73	20,429.74
Industrial	-	231.03	1,183.38	1,191.66	1,200.00	1,208.40	1,216.86	1,225.38	1,233.95	1,242.59	1,251.29	1,260.05	1,268.87	1,277.75
Lighting & Traffic Control	-	1,320.26	2,716.50	2,735.51	2,754.66	2,773.95	2,793.36	2,812.92	2,832.61	2,852.44	2,872.40	2,892.51	2,912.76	2,933.15
Agricultural	-	2.43	14.65	14.76	14.86	14.96	15.07	15.17	15.28	15.39	15.49	15.60	15.71	15.82
Total Customers		172,547	300,317	302,420	304,537	306,668	308,815	310,977	313,154	315,346	317,553	319,776	322,014	324,268
Energy Sales (KWh)														
Domestic	-	946,025,173	1,552,165,639	1,563,030,799	1,573,972,014	1,584,989,818	1,596,084,747	1,607,257,340	1,618,508,142	1,629,837,699	1,641,246,563	1,652,735,288	1,664,304,435	1,675,954,567
Commercial	-	302,811,887	929,407,882	935,913,737	942,465,133	949,062,389	955,705,826	962,395,767	969,132,537	975,916,465	982,747,880	989,627,115	996,554,505	1,003,530,386
Industrial	-	256,831,034	1,347,425,967	1,356,857,949	1,366,355,955	1,375,920,446	1,385,551,889	1,395,250,753	1,405,017,508	1,414,852,630	1,424,756,599	1,434,729,895	1,444,773,004	1,454,886,415
Lighting & Traffic Control	-	5,579,155	34,789,702	35,033,230	35,278,463	35,525,412	35,774,090	36,024,509	36,276,680	36,530,617	36,786,331	37,043,836	37,303,143	37,564,265
Agricultural	-	182,397	1,223,799	1,232,366	1,240,992	1,249,679	1,258,427	1,267,236	1,276,106	1,285,039	1,294,035	1,303,093	1,312,214	1,321,400
Total Energy Sales (KWh)		1,511,429,646	3,865,012,990	3,892,068,081	3,919,312,557	3,946,747,745	3,974,374,979	4,002,195,604	4,030,210,973	4,058,422,450	4,086,831,407	4,115,439,227	4,144,247,302	4,173,257,033

San Jose Community Choice Aggregation
Financial Proforma
Portfolio 100% Renewable

CCE Operating Costs	**2017 July - Dec**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Power Supply		$96,122,019	$271,228,510	$278,703,735	$283,617,954	$288,695,632	$293,863,324	$299,284,600	$304,891,244	$310,957,147	$316,743,162	$323,083,020	$329,452,156	$335,965,030
Billing & Data Management		$2,592,169	$4,504,761	$4,536,294	$4,568,048	$4,600,024	$4,632,224	$4,664,650	$4,697,303	$4,730,184	$4,763,295	$4,796,638	$4,830,214	$4,864,026
PG&E Fees		$1,267,182	$2,249,641	$2,310,697	$2,373,409	$2,437,823	$2,503,986	$2,571,944	$2,641,747	$2,713,444	$2,787,086	$2,862,728	$2,940,422	$3,020,225
Technical Services		$630,000	$1,120,000	$1,087,320	$1,002,946	$1,023,005	$1,043,465	$1,064,334	$1,085,621	$1,107,333	$1,129,480	$1,152,069	$1,175,111	$1,198,613
Staffing		$2,001,267	$3,837,839	$3,952,974	$4,071,563	$4,193,710	$4,319,521	$4,449,107	$4,582,580	$4,720,058	$4,861,659	$5,007,509	$5,157,734	$5,312,466
General & Administrative expenses		$790,000	$357,000	$312,120	$318,362	$378,851	$430,592	$395,283	$344,606	$351,498	$423,208	$486,826	$444,425	$380,473
Debt Service (CCE Bonds & Start-up Costs)		$1,170,882	$5,354,849	$5,354,849	$5,354,849	$5,354,849	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967
Start-Up Capital		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual Contribution to Reserves		$15,215,837	$28,105,722	$33,653,492	$41,949,698	$25,179,685		$0	$0	$0	$0	$0	$0	$0
New Programs Funding		$0	$0	$0	$0	$25,179,685	$58,899,293	$65,586,473	$72,435,460	$79,262,718	$86,375,608	$93,514,861	$100,986,772	$108,664,511
Uncollectibles		$744,952	$1,947,388	$1,980,154	$2,000,405	$2,022,052	$2,040,820	$2,068,125	$2,096,228	$2,127,051	$2,156,420	$2,188,725	$2,220,481	$2,252,766
Total Operating Costs		$120,534,308	$318,705,709	$331,891,635	$345,257,234	$359,065,316	$371,917,191	$384,268,482	$396,958,754	$410,153,399	$423,423,885	$437,276,343	$451,391,282	$465,842,078
Other Revenues		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement		$120,534,308	$318,705,709	$331,891,635	$345,257,234	$359,065,316	$371,917,191	$384,268,482	$396,958,754	$410,153,399	$423,423,885	$437,276,343	$451,391,282	$465,842,078
Average CCE Rate ($/kWh)		$0.2153	$0.1399	$0.1447	$0.1495	$0.1544	$0.1588	$0.1629	$0.1671	$0.1715	$0.1758	$0.1803	$0.1848	$0.1894
Average PG&E Generation Rate ($/kWh)		$0.0998	$0.1018	$0.1053	$0.1088	$0.1123	$0.1155	$0.1185	$0.1216	$0.1248	$0.1279	$0.1312	$0.1345	$0.1378
Total CCE Charges														
PG&E Non-bypassable Charges		$43,786,811	$100,824,918	$99,772,911	$98,773,937	$97,726,440	$97,186,895	$97,011,206	$96,818,510	$96,646,668	$96,392,064	$96,172,201	$95,912,225	$95,628,426
CCE Revenue Requirement		$120,534,308	$318,705,709	$331,891,635	$345,257,234	$359,065,316	$371,917,191	$384,268,482	$396,958,754	$410,153,399	$423,423,885	$437,276,343	$451,391,282	$465,842,078
Total CCE Generation Revenue Requirement		$164,321,119	$419,530,627	$431,664,545	$444,031,171	$456,791,756	$469,104,086	$481,279,688	$493,777,264	$506,800,067	$519,815,949	$533,448,544	$547,303,506	$561,470,504
Bundled PG&E Revenues		$308,259,271	$777,818,683	$804,528,994	$831,744,232	$859,796,536	$867,193,537	$893,516,155	$920,557,819	$948,530,875	$976,914,649	$1,006,342,598	$1,036,429,130	$1,067,273,911
Total CCE Customer Bill Revenues (Power Supply and Delivery)		$323,393,482	$803,885,471	$826,450,780	$849,531,904	$873,297,779	$877,140,597	$900,390,310	$924,262,547	$948,968,721	$973,985,061	$999,943,806	$1,026,459,449	$1,053,630,739
Savings		**($15,134,211)**	**($26,066,788)**	**($21,921,786)**	**($17,787,672)**	**($13,501,242)**	**($9,947,060)**	**($6,874,154)**	**($3,704,728)**	**($437,847)**	**$2,929,588**	**$6,398,793**	**$9,969,681**	**$13,643,172**
Percent Savings		**-4.9%**	**-3.4%**	**-2.7%**	**-2.1%**	**-1.6%**	**-1.1%**	**-0.8%**	**-0.4%**	**0.0%**	**0.3%**	**0.6%**	**1.0%**	**1.3%**
Reserves		$15,215,837	$28,105,722	$33,653,492	$41,949,698	$50,359,371	$58,899,293	$65,586,473	$72,435,460	$79,262,718	$86,375,608	$93,514,861	$100,986,772	$108,664,511
Cummulative Reserves		$15,215,837	$43,321,559	$76,975,051	$118,924,749	$144,104,434	$144,104,434	$144,104,434	$144,104,434	$144,104,434	$144,104,434	$144,104,434	$144,104,434	$144,104,434

Appendix C – Staffing and Infrastructure Detail

	Year	2017						2018											
	Phase	Prestart-up						Phase 1					Phase 2					Phase 3	
	Month	July, 2017	August	September	October	November	December	January, 2018	February	March	April	May	June	July	August	September	October	November	December
Staffing Cost (including benefits)	Salary																		
Executive Director	300,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,750	$ 25,750	$ 25,750	$ 25,750	$ 25,750	$ 25,750	$ 25,750	$ 25,750	$ 25,750	$ 25,750	$ 25,750	$ 25,750
General Council & Director of Government Affairs	233,993	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,084	$ 20,084	$ 20,084	$ 20,084	$ 20,084	$ 20,084	$ 20,084
Director of Power Resources	233,993	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,084	$ 20,084	$ 20,084	$ 20,084	$ 20,084	$ 20,084	$ 20,084
Regulatory/Legislative Analyst	181,723	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Administrative Assistant	109,963	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438
Director of Administration and Finance	233,993	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Finance Manager	203,943	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,505	$ 17,505	$ 17,505	$ 17,505	$ 17,505	$ 17,505	$ 17,505
Director of Marketing and Public Affairs	233,993	$ 19,499	$ 19,499	$ 19,499	$ 19,499	$ 19,499	$ 19,499	$ 20,084	$ 20,084	$ 20,084	$ 20,084	$ 20,084	$ 20,084	$ 20,084	$ 20,084	$ 20,084	$ 20,084	$ 20,084	$ 20,084
Power Supply Compliance Specialist	190,340	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,338	$ 16,338	$ 16,338	$ 16,338	$ 16,338	$ 16,338	$ 16,338
Power Resource Planning and Program Analyst	190,340	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,338	$ 16,338
Community Outreach Manager	190,340	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,338	$ 16,338	$ 16,338	$ 16,338	$ 16,338	$ 16,338	$ 16,338
Account Service Manager	183,768	$ 15,314	$ 15,314	$ 15,314	$ 15,314	$ 15,314	$ 15,314	$ 15,773	$ 15,773	$ 15,773	$ 15,773	$ 15,773	$ 15,773	$ 15,773	$ 15,773	$ 15,773	$ 15,773	$ 15,773	$ 15,773
Account Representatives	109,963	$ 9,164	$ 9,164	$ 9,164	$ 9,164	$ 9,164	$ 9,164	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438	$ 9,438
Communication Specialists	164,775	$ 13,731	$ 13,731	$ 13,731	$ 13,731	$ 13,731	$ 13,731	$ 14,143	$ 14,143	$ 14,143	$ 14,143	$ 14,143	$ 14,143	$ 14,143	$ 14,143	$ 14,143	$ 14,143	$ 14,143	$ 14,143
Executive Assistant/Council Clerk	166,494	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,291	$ 14,291	$ 14,291	$ 14,291	$ 14,291	$ 14,291	$ 14,291
Administrative Analysts	167,397	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,368	$ 14,368	$ 14,368	$ 14,368	$ 14,368	$ 14,368	$ 14,368
Total Staffing Costs		**$ 82,708**	**$ 82,708**	**$ 82,708**	**$ 82,708**	**$ 82,708**	**$ 82,708**	**$ 93,709**	**$ 93,709**	**$ 93,709**	**$ 93,709**	**$ 93,709**	**$ 211,562**	**$ 211,562**	**$ 211,562**	**$ 211,562**	**$ 211,562**	**$ 227,741**	**$ 227,741**
Consulting Costs																			
Legal/Regulatory		$ 20,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000
Advertising/Communication		$ -	$ -	$ -	$ -	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000
Data Management		$ -	$ -	$ -	$ -	$ -	$ -	$ 2,820	$ 2,637	$ 2,926	$ 2,811	$ 2,706	$ 364,737	$ 365,558	$ 366,439	$ 366,148	$ 366,558	$ 374,309	$ 374,520
Power Supply Management																			
Financial Consulting		$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Technical Consultant		$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Other Start-up/ City Functions		$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 15,000	$ 15,000
Total Consulting Costs		**$ 120,000**	**$ 150,000**	**$ 150,000**	**$ 150,000**	**$ 175,000**	**$ 175,000**	**$ 157,820**	**$ 157,637**	**$ 157,926**	**$ 157,811**	**$ 157,706**	**$ 519,737**	**$ 520,558**	**$ 521,439**	**$ 521,148**	**$ 521,558**	**$ 504,309**	**$ 504,520**
Infrastructure Costs																			
Computers		$ 25,000	$ -	$ -	$ -	$ -	$ -	$ 5,000	$ -	$ -	$ -	$ -	$ 35,000	$ -	$ -	$ -	$ -	$ 5,000	$ -
Furnishings		$ 25,000	$ -	$ -	$ -	$ -	$ -	$ 5,000	$ -	$ -	$ -	$ -	$ 35,000	$ -	$ -	$ -	$ -	$ 5,000	$ -
Office Space		$ -	$ -	$ -	$ -	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
Utilities and other Office supplies		$ -	$ -	$ -	$ -	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Miscellaneous		$ -	$ -	$ -	$ -	$ 50,000	$ 50,000	$ -	$ -	$ -	$ 100,000	$ 100,000	$ -	$ -	$ -	$ 100,000	$ 100,000	$ -	$ -
Other		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Infrastructure Costs		**$ 50,000**	**$ -**	**$ -**	**$ -**	**$ 75,000**	**$ 75,000**	**$ 35,000**	**$ 25,000**	**$ 25,000**	**$ 125,000**	**$ 125,000**	**$ 95,000**	**$ 25,000**	**$ 25,000**	**$ 125,000**	**$ 125,000**	**$ 35,000**	**$ 25,000**
Total Staffing and Infrastructure		**$ 252,708**	**$ 232,708**	**$ 232,708**	**$ 232,708**	**$ 332,708**	**$ 332,708**	**$ 286,529**	**$ 276,347**	**$ 276,636**	**$ 376,520**	**$ 376,415**	**$ 826,299**	**$ 757,120**	**$ 758,001**	**$ 857,710**	**$ 858,120**	**$ 767,050**	**$ 757,261**

Staffing Cost (including benefits)	Salary	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Executive Director	300,000	$ 150,000	$ 309,000	$ 318,270	$ 327,818	$ 337,653	$ 347,782	$ 358,216	$ 368,962	$ 380,031	$ 391,432	$ 403,175	$ 415,270	$ 427,728	$ 440,560
General Council & Director of Government Affairs	233,993	$ -	$ 140,591	$ 248,244	$ 255,691	$ 263,362	$ 271,262	$ 279,400	$ 287,782	$ 296,416	$ 305,308	$ 314,467	$ 323,902	$ 333,619	$ 343,627
Director of Power Resources	233,993	$ -	$ 140,591	$ 248,244	$ 255,691	$ 263,362	$ 271,262	$ 279,400	$ 287,782	$ 296,416	$ 305,308	$ 314,467	$ 323,902	$ 333,619	$ 343,627
Regulatory/Legislative Analyst	181,723	$ -	$ -	$ 192,790	$ 198,574	$ 204,531	$ 210,667	$ 216,987	$ 223,496	$ 230,201	$ 237,107	$ 244,220	$ 251,547	$ 259,093	$ 266,866
Administrative Assistant	109,963	$ -	$ 113,262	$ 116,660	$ 120,159	$ 123,764	$ 127,477	$ 131,301	$ 135,240	$ 139,298	$ 143,477	$ 147,781	$ 152,214	$ 156,781	$ 161,484
Director of Administration and Finance	233,993	$ -	$ -	$ 248,244	$ 255,691	$ 263,362	$ 271,262	$ 279,400	$ 287,782	$ 296,416	$ 305,308	$ 314,467	$ 323,902	$ 333,619	$ 343,627
Finance Manager	203,943	$ -	$ 122,536	$ 216,363	$ 222,854	$ 229,540	$ 236,426	$ 243,519	$ 250,824	$ 258,349	$ 266,099	$ 274,082	$ 282,305	$ 290,774	$ 299,497
Director of Marketing and Public Affairs	233,993	$ 116,997	$ 241,013	$ 248,244	$ 255,691	$ 263,362	$ 271,262	$ 279,400	$ 287,782	$ 296,416	$ 305,308	$ 314,467	$ 323,902	$ 333,619	$ 343,627
Power Supply Compliance Specialist	190,340	$ -	$ 114,363	$ 201,932	$ 207,990	$ 214,229	$ 220,656	$ 227,276	$ 234,094	$ 241,117	$ 248,350	$ 255,801	$ 263,475	$ 271,379	$ 279,521
Power Resource Planning and Program Analyst	190,340	$ -	$ 32,675	$ 403,863	$ 415,979	$ 428,458	$ 441,312	$ 454,552	$ 468,188	$ 482,234	$ 496,701	$ 511,602	$ 526,950	$ 542,758	$ 559,041
Community Outreach Manager	190,340	$ -	$ 114,363	$ 201,932	$ 207,990	$ 214,229	$ 220,656	$ 227,276	$ 234,094	$ 241,117	$ 248,350	$ 255,801	$ 263,475	$ 271,379	$ 279,521
Account Service Manager	183,768	$ 91,884	$ 189,282	$ 194,960	$ 200,809	$ 206,833	$ 213,038	$ 219,429	$ 226,012	$ 232,792	$ 239,776	$ 246,969	$ 254,379	$ 262,010	$ 269,870
Account Representatives	109,963	$ 54,981	$ 113,262	$ 116,660	$ 120,159	$ 123,764	$ 127,477	$ 131,301	$ 135,240	$ 139,298	$ 143,477	$ 147,781	$ 152,214	$ 156,781	$ 161,484
Communication Specialists	164,775	$ 82,388	$ 169,719	$ 349,620	$ 360,109	$ 370,912	$ 382,039	$ 393,501	$ 405,306	$ 417,465	$ 429,989	$ 442,888	$ 456,175	$ 469,860	$ 483,956
Executive Assistant/Council Clerk	166,494	$ -	$ 100,035	$ 176,634	$ 181,933	$ 187,391	$ 193,013	$ 198,803	$ 204,767	$ 210,910	$ 217,237	$ 223,754	$ 230,467	$ 237,381	$ 244,503
Administrative Analysts	167,397	$ -	$ 100,577	$ 355,182	$ 365,838	$ 376,813	$ 388,117	$ 399,761	$ 411,753	$ 424,106	$ 436,829	$ 449,934	$ 463,432	$ 477,335	$ 491,655
Total Staffing Costs		**$ 496,250**	**$ 2,001,267**	**$ 3,837,839**	**$ 3,952,974**	**$ 4,071,563**	**$ 4,193,710**	**$ 4,319,521**	**$ 4,449,107**	**$ 4,582,580**	**$ 4,720,058**	**$ 4,861,659**	**$ 5,007,509**	**$ 5,157,734**	**$ 5,312,466**
Consulting Costs															
Legal/Regulatory		$ 270,000	$ 360,000	$ 360,000	$ 312,120	$ 212,242	$ 216,486	$ 220,816	$ 225,232	$ 229,737	$ 234,332	$ 239,019	$ 243,799	$ 248,675	$ 253,648
Advertising/Communication		$ 50,000	$ 300,000	$ 120,000	$ 122,400	$ 124,848	$ 127,345	$ 129,892	$ 132,490	$ 135,139	$ 137,842	$ 140,599	$ 143,411	$ 146,279	$ 149,205
Data Management		$ -	$ 2,592,169	$ 4,504,761	$ 4,536,294	$ 4,568,048	$ 4,600,024	$ 4,632,224	$ 4,664,650	$ 4,697,303	$ 4,730,184	$ 4,763,295	$ 4,796,638	$ 4,830,214	$ 4,864,026
Power Supply Management		$ -	$ -	$ -											
Financial Consulting		$ 300,000	$ 600,000	$ 640,000	$ 652,800	$ 665,856	$ 679,173	$ 692,757	$ 706,612	$ 720,744	$ 735,159	$ 749,862	$ 764,859	$ 780,156	$ 795,760
Technical Consultant		$ 60,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000
Other Start-up/ City Functions		$ 240,000	$ 430,000	$ 180,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000
Total Consulting Costs		**$ 920,000**	**$ 4,402,169**	**$ 5,924,761**	**$ 6,043,614**	**$ 5,990,994**	**$ 6,043,029**	**$ 6,095,689**	**$ 6,148,984**	**$ 6,202,923**	**$ 6,257,517**	**$ 6,312,775**	**$ 6,368,707**	**$ 6,425,325**	**$ 6,482,639**
Infrastructure Costs															
Computers		$ 25,000	$ 45,000	$ 25,500	$ -	$ -	$ 27,061	$ 49,684	$ 28,717	$ -	$ -	$ 32,340	$ 60,564	$ 35,706	$ -
Furnishings		$ 25,000	$ 45,000	$ 25,500	$ -	$ -	$ 27,061	$ 49,684	$ 28,717	$ -	$ -	$ 32,340	$ 60,564	$ 35,706	$ -
Office Space		$ 30,000	$ 180,000	$ 183,600	$ 187,272	$ 191,017	$ 194,838	$ 198,735	$ 202,709	$ 206,763	$ 210,899	$ 215,117	$ 219,419	$ 223,807	$ 228,284
Utilities and other Office supplies		$ 20,000	$ 120,000	$ 122,400	$ 124,848	$ 127,345	$ 129,892	$ 132,490	$ 135,139	$ 137,842	$ 140,599	$ 143,411	$ 146,279	$ 149,205	$ 152,189
Miscellaneous		$ 100,000	$ 400,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Infrastructure Costs		**$ 200,000**	**$ 790,000**	**$ 357,000**	**$ 312,120**	**$ 318,362**	**$ 378,851**	**$ 430,592**	**$ 395,283**	**$ 344,606**	**$ 351,498**	**$ 423,208**	**$ 486,826**	**$ 444,425**	**$ 380,473**
Total Staffing and Infrastructure Cost		**$ 1,616,250**	**$ 7,193,436**	**$ 10,119,599**	**$ 10,308,708**	**$ 10,380,919**	**$ 10,615,590**	**$ 10,845,802**	**$ 10,993,374**	**$ 11,130,109**	**$ 11,329,072**	**$ 11,597,642**	**$ 11,863,043**	**$ 12,027,484**	**$ 12,175,578**

Appendix D – Cities/Counties Evaluating CCA Feasibility

	CCA Name	Service Area	Start Date	IOU
Operational				
	Marin Clean Energy	Marin County, Napa County, part of Contra Costa and Solano Counties	May 2010	PG&E
	Sonoma Clean Power	Sonoma & Mendocino Counties	May 2014	PG&E
	Lancaster Choice Energy	City of Lancaster	May 2015	PG&E
	Clean Power San Francisco	City of San Francisco	May 2016	PG&E
	Peninsula Clean Energy	San Mateo County	October 2016	PG&E
Exploring/In Process				
	Redwood Coast Energy Authority	Humboldt County	May 2017	PG&E
	East Bay Community Energy	Alameda County		PG&E
	TBD	Butte County		PG&E
	TBD	City of San José		PG&E
	TBD	Contra Costa County		PG&E
	TBD	Humboldt County		PG&E
	LA Community Choice Energy	LA County		PG&E
	TBD	Mendocino County		PG&E
	TBD	Monterey County		PG&E
	TBD	Placer County		PG&E
	TBD	Riverside County		PG&E
	TBD	San Benito County		PG&E
	TBD	San Bernardino County		PG&E
	TBD	San Diego County		SDG&E
	TBD	San Luis Obispo County		PG&E
	TBD	Santa Barbara County		PG&E/PG&E
	Silicon Valley Clean Energy	Santa Clara County	April 2017	PG&E
	TBD	Santa Cruz County		PG&E

Appendix E – Glossary

aMW: Average annual Megawatt. A unit of energy output over a year that is equal to the energy produced by the continuous operation of one megawatt of capacity over a period of time (8,760 megawatt-hours).

Basis Difference (Natural Gas): The difference between the price of natural gas at the Henry Hub natural gas distribution point in Erath, Louisiana, which serves as a central pricing point for natural gas futures, and the natural gas price at another hub location (such as for Southern California).

Buckets: Buckets 1-3 refer to different types of renewable energy contracts according to the Renewable Portfolio Standards requirements. Bucket 1 are traditional contracts for delivery of electricity directly from a generator within or immediately connected to California. These are the most valuable and make up the majority of the RECS that are required for LSEs to be RPS compliant. Buckets 2 and 3 have different levels of intermediation between the generation and delivery of the energy from the generating resources.

Bundled Customers: Electricity customers who receive all their services (transmission, distribution and supply) from the Investor-Owned Utility.

California Independent System Operator (CAISO): The organization responsible for managing the electricity grid and system reliability within the former service territories of the three California IOUs.

California Clean Power (CCP): A private company providing wholesale supply and other services to CCAs.

California Energy Commission (CEC): The state regulatory agency with primary responsibility for enforcing the Renewable Portfolio Standards law as well as a number of other, electric-industry related rules and policies.

California Public Utilities Commission (CPUC): The state agency with primary responsibility for regulating IOUs, as well as Direct Access (ESP) and CCA entities.

Capacity Factor: the ratio of an electricity generating resource's actual output over a period of time to its potential output if it were possible to operate at full nameplate capacity continuously over the same period. Intermittent renewable resources, like wind and solar, typically have lower capacity factors than traditional fossil fuel plants because the wind and sun do not blow or shine consistently.

CleanPowerSF: CCA program serving customers within the City of San Francisco. CleanPowerSF began service to 7,800 "Phase 1" customers in May 2016.

Climate Zone: A geographic area with distinct climate patterns necessitating varied energy demands for heating and cooling.

Coincident Peak: Demand for electricity among a group of customers that coincides with peak total demand on the system.

Community Choice Aggregation (CCA): Method available through California law to allow Cities and Counties to aggregate their citizens and become their electric generation provider.

Community Choice Energy: A City, County or Joint Powers Agency procuring wholesale power to supply to retail customers.

Community Choice Partners: A private company providing services to CCAs in California.

Congestion Revenue Rights (CRRs): Financial rights that are allocated to Load Serving Entities to offset differences between the prices where their generation is located and the price that they pay to serve their load. These rights may also be bought and sold through an auction process. CRRs are part of the CAISO market design.

Demand Side Resources: Energy efficiency and load management programs that reduce the amount of energy that would otherwise be consumed by a customer of an electric utility.

Demand Response (DR): Electric customers who have a contract to modify their electricity usage in response to requests from a utility or other electric entity. Typically, will be used to lower demand during peak energy periods, but may be used to raise demand during periods of excess supply.

Direct Access: Large power consumers which have opted to procure their wholesale supply independently of the IOUs through an Electricity Service Provider.

EEI (Edison Electric Institute) Agreement: A commonly used enabling agreement for transacting in wholesale power markets.

Electric Service Providers (ESP): An alternative to traditional utilities. They provide electric services to retail customers in electricity markets that have opened their retail electricity markets to competition. In California the Direct Access program allows large electricity customers to opt-out of utility-supplied power in favor of ESP-provided power. However, there is a cap on the amount of Direct Access load permitted in the state.

Electric Tariffs: The rates and terms applied to customers by electric utilities. Typically have different tariffs for different classes of customers and possibly for different supply mixes.

Enterprise Model: When a City or County establish a CCA by themselves as an enterprise within the municipal government.

Federal Tax Incentives: There are two Federal tax incentive programs. The Investment Tax Credit (ITC) provides payments to solar generators. The Production Tax Credit (PTC) provides payments to wind generators.

Feed-in Tariff (FIT): A tariff that specifies what generators who are connected to the distribution system are paid.

Forward Prices: Prices for contracts that specify a future delivery date for a commodity or other security. There are active, liquid forward markets for electricity to be delivered at a number of Western electricity trading hubs, including NP15 which corresponds closely to the price location which the City of Davis will pay to supply its load.

Implied Heat Rate: A calculation of the day-ahead electric price divided by the day-ahead natural gas price. Implied heat rate is also known as the 'break-even natural gas market heat rate,' because only a natural gas generator with an operating heat rate (measure of unit efficiency) below the implied heat rate value can make money by burning natural gas to generate power. Natural gas plants with a higher operating heat rate cannot make money at the prevailing electricity and natural gas prices.

Integrated Resource Plan: A utility's plan for future generation supply needs.

Investor-Owned Utility (IOU): For profit regulated utilities. Within California there are three IOUs - Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric.

ISDA (International Swaps and Derivatives Association): Popular form of bilateral contract to facilitate wholesale electricity trading.

Joint Powers Agency (JPA): A legal entity comprising two or more public entities. The JPA provides a separation of financial and legal responsibility from its member entities.

Lancaster Choice Energy (LCE): A single-jurisdiction CCE serving residents of the City of Lancaster in Southern California. LCE launched service in October 2015 and served 51,000 customers as of the publication of this report.

LEAN Energy (Local Energy Aggregation Network): A not-for-profit organization dedicated to expanding Community Choice Aggregation nationwide.

Load Forecast: A forecast of expected load over some future time horizon. Short-term load forecasts are used to determine what supply sources are needed. Longer-term load forecasts are used for budgeting and long-term resource planning.

Marginal Unit: An additional unit of power generation to what is currently being produced. At and electric power plant, the cost to produce a marginal unit is used to determine the cost of increasing power generation at that source.

Marin Clean Energy (MCE): The first CCA in California now serving residents and businesses in the Counties of Marin and Napa, and the Cities of Richmond, Benicia, El Cerrito, San Pablo, Walnut Creek, and Lafayette.

Market Redesign and Technology Upgrade (MRTU): CAISO's redesigned, nodal (as opposed to zonal) market that went live in April of 2009.

Net Energy Metering (NEM): The program and rates that pertain to electricity customers who also generate electricity, typically from rooftop solar panels.

Nonbypassable Charges: Charges applied to all customers receiving service from Investor-Owned Utilities in California, but which are separated into a separate charge for departing load customers, such as Community Choice Aggregation and Direct Access Customers. These charges include charges for the Public Purpose Programs (PPP), Nuclear Decommissioning (ND), California Department of Water Resources Bond (CDWR), Power Charge Indifference Adjustment (PCIA), Energy Cost Recovery Amount (ECRA), Competition Transition Charge (CTC), Cost Allocation Mechanism (CAM).

Non-Coincident Peak: Energy demand by a customer during periods that do not coincide with maximum total system load.

Non-Renewable Power: Electricity generated from non-renewable sources or that does not come with a Renewable Energy Credit (REC).

NP15: Refers to a wholesale electricity pricing hub - North of Path 15 - which roughly corresponds to PG&E's service territory. Forward and Day-Ahead power contracts for Northern California typically provide for delivery at NP15. It is not a single location, but an aggregate based on the locations of all the generators in the region.

On-Bill Repayment (OBR): Allows electric customers to pay for financed improvements such as energy efficiency measures through monthly payments on their electricity bills.

Operate on the Margin: Operation of a business or resource at the limit of where it is profitable.

Opt-Out: Community Choice Aggregation is, by law, an opt-out program. Customers within the borders of a CCA are automatically enrolled within the CCA unless they proactively opt-out of the program.

Peninsula Clean Energy (PCE): Community Choice Aggregation program serving residents and businesses of San Mateo County. PCE launched in October of 2016.

Power Charge Indifference Adjustment (PCIA): A charge applied to customers who leave IOU service to become Direct Access or CCA customers. The charge is meant to compensate the IOU for costs that it has previously incurred to serve those customers.

Power Purchase Agreement (PPA): The standard term for bilateral supply contracts in the electricity industry.

Renewable Energy Credits (RECs): The renewable attributes from RPS-qualified resources which must be registered and retired to comply with RPS standards.

Resource Adequacy (RA): The requirement that a Load-Serving Entity own or procure sufficient generating capacity to meet its peak load plus a contingency amount (15 percent in California) for each month.

Renewable Portfolio Standard (RPS): The state-based requirement to procure a certain percentage of load from RPS-certified renewable resources.

Scheduling Coordinator: An entity that is approved to interact directly with CAISO to schedule load and generation. All CAISO participants must be or have an SC.

Scheduling Agent: A person or service that forecasts and monitors short term system load requirements and meets these demands by scheduling power resource to meet that demand.

Silicon Valley Clean Energy (SVCE): CCA serving customers in twelve communities within Santa Clara County including the cities of Campbell, Cupertino, Gilroy, Los Altos, Los Altos Hills, Los Gatos, Monte Sereno, Morgan Hill, Mountain View, Saratoga, Sunnyvale, and the County of Santa Clara. As of the date of completion of this study, SVCE had not yet launched service.

Sonoma Clean Power (SCP): A CCA serving Sonoma County and Sonoma County cities. On December 29th, SCP received approval of their implementation plan from the California Public Utilities Commission to extend service into Mendocino County.

Spark Spread: The theoretical grow margin of a gas-fired power plant from selling a unit of electricity, having bought the fuel required to produce this unit of electricity. All other costs (capital, operation and maintenance, etc.) must be covered from the spark spread.

Supply Stack: Refers to the generators within a region, stacked up according to their marginal cost to supply energy. Renewables are on the bottom of the stack and peaking gas generators on the top. Used to provide insights into how the price of electricity is likely to change as the load changes.

Inland Choice Power (ICP): Refers collectively to the three councils of governments: Coachella Valley Association of Governments (CVAG), San Bernardino Associated Governments (SANBAG), and Western Riverside Council of Governments (WRCOG).

Weather Adjusted: Normalizing energy use data based on differences in the weather during the time of use. For instance, energy use is expected to be higher on extremely hot days when air conditioning is in higher demand than on days with comfortable temperature. Weather adjustment normalizes for this variation.

Western Electric Coordinating Council (WECC): The organization responsible for coordinating planning and operation on the Western electric grid.

Wholesale Power: Large amounts of electricity that are bought and sold by utilities and other electric companies in bulk at specific trading hubs. Quantities are measured in MWs, and a standard wholesale contract is for 25 MW for a month during heavy-load or peak hours (7am to 10 pm, Mon-Sat), or light-load or off-peak hours (all the other hours).

Western States Power Pool (WSPP) Agreement: Common, standardized enabling agreement to transact in the wholesale power markets.

Appendix F – Power Supply

Wholesale Market Prices

Natural gas-fired power plants are typically the marginal power supply resource that sets the electricity market price in northern California and elsewhere in the Western Energy Coordinating Council (WECC) footprint. Resources that operate on the margin only run when it is economic to do so (i.e. when the costs associated with running the resources are less than the revenue made in the wholesale market). WECC creates, monitors and enforces reliability standards applicable to power supply resources west of the Rocky Mountains. As the market price of electricity is usually set by the cost of the marginal unit, a wholesale market price forecast has been developed using a forecast of natural gas prices and the projected relationship between gas prices and electricity prices (also defined as market-implied heat rates or spark spreads). The projected market-implied heat rates reflect the average efficiency of gas-fired power plants that operate on the margin in a given month in California. Projected heat rates are based on historic market-implied heat rates, which are calculated by dividing historic northern California (NP15) wholesale market prices by historic northern California natural gas prices. A natural gas price forecast has been developed based on NYMEX forward gas prices for the Henry Hub trading hub and forward northern California basis differentials. A basis differential is the difference between the price of gas at Henry Hub and the price of gas at a regional trading hub, such as PG&E Citygate in northern California. Projected market heat rates have then been applied to the northern California natural gas price forecast to calculate a wholesale electric market price forecast for northern California.

The following steps have been taken to produce the wholesale electric market price forecast:

1. Forward prices for natural gas at Henry Hub are available through June 2025.
2. The PG&E Citygate (northern California) basis differential is used to adjust the Henry Hub forward prices to PG&E Citygate (northern California) prices. PG&E Citygate forward natural gas prices are equal to NYMEX forward prices (Henry Hub) plus the PG&E Citygate basis. The PG&E Citygate basis forward curve is available through December 2021. After December 2021, the monthly PG&E Citygate basis is assumed to increase at 5 percent.
3. Projected monthly market-implied heat rates are multiplied by forecast PG&E Citygate natural gas prices to calculate forecast northern California wholesale market prices.
4. Projected heat rates are based on historic heat rates (northern California/NP15 wholesale electricity prices divided by PG&E Citygate natural gas prices).
5. Monthly market-implied heat rates are held constant in all years.
6. Forecast northern California wholesale electric market prices are escalated by a 3.5 percent annual growth rate after June 2025.
7. Forecast northern California wholesale electric market prices are benchmarked against other market price forecasts.

Exhibit A-1 below shows the forecast of northern California natural gas prices. The seasonal shape reflects the fact that natural gas prices are highest during the winter when there is heating load and lowest in the spring when there is neither heating nor cooling (air conditioning) load.

Exhibit A-1
Forecast PG&E Citygate (Northern California) Natural Gas Price

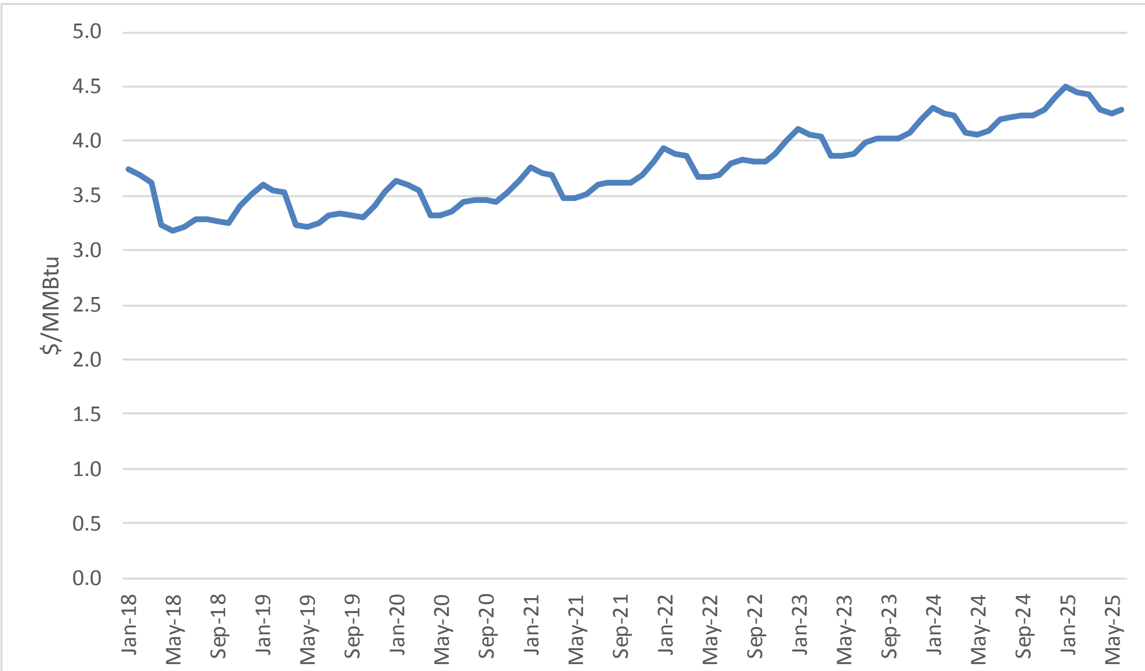
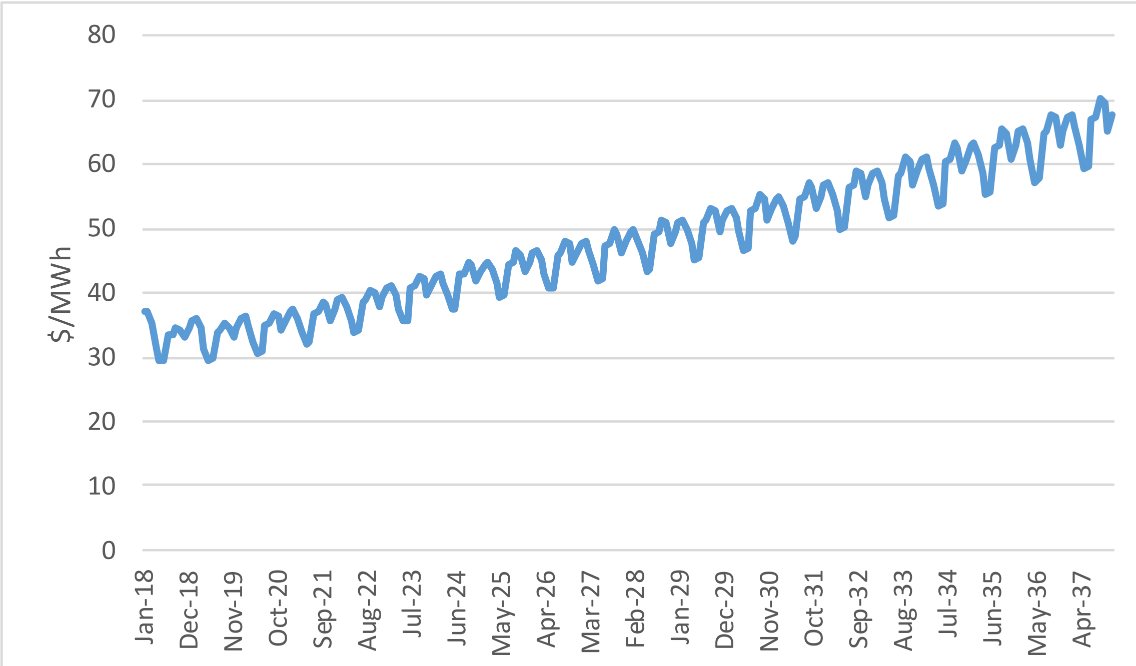


Exhibit A-2 below shows the resulting monthly northern California wholesale electric market price forecast. The levelized value of market prices over the study period is $46/MWh (2016$) assuming a 4 percent discount rate. The seasonal shape of electric market prices is similar to the shape of natural gas prices. Electric market prices peak in the winter and summer when there is heating and cooling load.

Exhibit A-2
Forecast Northern California Wholesale Market Prices



Ancillary and Congestion Costs

SJCE will pay the CAISO for transmission congestion and ancillary services. Transmission congestion occurs when there is insufficient capacity to meet the demands of all transmission customers. Congestion refers to a shortage of transmission capacity to supply a waiting market, and is marked by systems running at full capacity and still being unable to serve the needs of all customers. The transmission system is not allowed to run above its rated capacities. Congestion is managed by the CAISO by charging congestion charges in the day-ahead market. Congestion charges can be managed through the use of Congestion Revenue Rights (CRR). CRRs are financial instruments made available through a CRR allocation, a CRR auction, and a secondary registration system. CRR holders manage variability in congestion costs. SJCE's congestion charges will depend on the transmission paths used to bring resources to load. As such, the location of generating resources used to serve SJCE load will impact these congestion costs.

The Grid Management Charge (GMC) is the vehicle through which the CAISO recovers its administrative and capital costs from the entities that utilize the CAISO's services. Based on a survey of GMC costs currently paid by CAISO participants, SJCE's GMC costs are expected to be near $0.5/MWh.

The CAISO performs annual studies to identify the minimum local resource capacity required in each local area to meet established reliability criteria. Load serving entities receive a proportional allocation of the minimum required local resource capacity by transmission access charge area, and submit resource adequacy plans to show that they have procured the necessary capacity.

Depending on these results of the annual studies, there may be costs associated with local capacity requirements for SJCE.

Because generation is delivered as it is produced and, particularly with respect to renewables can be intermittent, deliveries need to be firmed using ancillary services to meet SJCE's load requirements. Ancillary services will need to be purchased from the CAISO. Regulation and operating reserves are described below.

- *Regulation Service:* Regulation service is necessary to provide for the continuous balancing of resources with load and for maintaining scheduled interconnection frequency at 60 cycles per second (60 Hertz). Regulation and frequency response service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load.

- *Operating Reserves - Spinning Reserve Service:* Spinning reserve service is needed to serve load immediately in the event of a system contingency. Spinning reserve service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service.

- *Operating Reserves – Non-Spinning Reserve Service:* Non-spinning reserve service is available within a short period of time to serve load in the event of a system contingency. Non-spinning reserve service may be provided by generating units that are on-line but not providing power, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service.

Based on a survey of ancillary service costs currently paid by CAISO participants, SJCE's ancillary service costs are estimated to be near $5/MWh. The Plan's base case will assume SJCE's ancillary service costs are $5/MWh in 2017, escalating by 1.5 percent annually thereafter. Serving a greater percentage of load with renewables will likely result in increased grid congestion and higher ancillary service costs. For this reason, the ancillary service costs have been increased in the 10 percent above PG&E, 20 percent above PG&E and 100 percent renewables Scenarios included in this Plan as shown below in Exhibit A-3.

Exhibit A-3
Base Case Ancillary Service Costs in Resource Portfolios

Portfolio	2017 Ancillary Service Costs	Annual Escalation Factor
1- Match PG&E's Renewable Procurement Plan	5.0	1.5%
2- Exceed PG&E's Renewable Procurement Plan by 10%	5.5	1.6%
3- Exceed PG&E's Renewable Procurement Plan by 20%	6.0	1.7%
4- Serve 100% of Retail Load with Renewables	7.5	2.0%

Scheduling Coordinator Services

A scheduling coordinator provides day-ahead and real-time power and transmission scheduling services. Scheduling coordinators bear the responsibility for accurate and timely load forecasting and resource scheduling including wholesale power purchases and sales required to maintain hourly load/resource balances. A scheduling coordinator needs to provide the marketing expertise and analytical tools required to optimally dispatch SJCE's surplus resources on a monthly, daily and hourly basis.

Inside each hour, the CAISO Energy Imbalance Market (EIM) takes over load/resource balancing duties. The EIM automatically balances loads and resources every fifteen minutes and dispatches least-cost resources every 5-minutes. The EIM allows balancing authorities to share reserves, and more reliably and efficiently integrate renewable resources across a larger geographic region.

Within a given hour, metered energy (i.e., actual usage) may differ from supplied power due to hourly variations in resource output or unexpected load deviations. Deviations between metered energy and supplied power are accounted for by the EIM. The imbalance market is used to resolve imbalances between supply and demand. The EIM deals only with energy, not ancillary services or reserves (which are addressed in the next section).

The EIM optimally dispatches participating resources to maintain load/resource balance in real-time. The EIM uses the CAISO's real-time market, which uses Security Constrained Economic Dispatch (SCED). SCED finds the lowest cost generation to serve the load taking into account operational constraints such as limits on generators or transmission facilities. The five-minute market automatically procures generation needed to meet future imbalances. The purpose of the five-minute market is to meet the very short term load forecast. Dispatch instructions are effectuated through the Automated Dispatch System (ADS).

The CAISO is the market operator, and runs and settles EIM transactions. SJCE's scheduling coordinator will submit SJCE's load and resource information to the market operator. EIM processes are running continuously for every fifteen-minute and five-minute intervals, producing dispatch instructions and prices.

Participating resource scheduling coordinators submit energy bids to let the market operator know that they are available to participate in the real-time market to help resolve energy imbalances. Resource schedulers may also submit an energy bid to declare that resources will increase or decrease generation if a certain price is struck. An energy bid is comprised of a megawatt value and a price. For every increase in megawatt level, the settlement price also increases.

The CAISO calculates financial settlements based on the difference between schedules and actual meter data, and bid prices during each hour. Locational Marginal Prices (LMP) are used in settlement calculations. The LMP is the price of a unit of energy at a particular location at a given time. LMPs are influenced by nearby generation, load level, and transmission constraints and losses.